Minnesota Department of Commerce
Division of Energy Resources
Information Request

Docket Number:	E015/GR-16-664	☐Nonpublic ☒Public	
Requested From:	Minnesota Power	Date of Request:	4/13/2017
Type of Inquiry:	Financial	Response Due:	4/25/2017

Requested by: Nancy Campbell/Dale Lusti/Lerma La Plante
Email Address(es): nancy.campbell@state.mn.us
Phone Number(s): 651-539-1821

Request Number: 2105
Topic: Transmission Capital 2016 Actuals
Reference(s): Fleege Direct, Schedule 1

Request:

(A) Please update 2016 Forecast column with 2016 Actuals for Transmission Capital Investment on Schedule 1. For any increases, please explain reason for increases.

(B) Please calculate the rate case adjustments (for rate base and income statement) as a result of updating to 2016 actuals (2017 beginning of year balance for TY) for transmission capital. Please show all supporting calculations. Please include estimated total revenue requirement impact.

RESPONSE:

(A) Please refer to LPI IR 31 Supplement for the update requested to 2016 Actuals. The North Shore Loop Transmission Project was the only project with 2016 Actual costs higher than the 2016 Forecast amounts. The North Shore Loop Transmission Project 2016 Actuals increased $0.58 million over the 2016 Forecast, partially due to an increase in civil work necessitated by underground rock at the Minntac 230kV Ring Bus project paired with an increase of cost of required materials at the Forbes-Add 2TR project. The balance of the increase was due to timing of work completed at the North Shore Switching Station, which is a multi-year project. A portion of the work initially planned (and therefore budgeted) to be completed during 2017 was completed in 2016.

(B) An estimate of the total revenue requirement impact as requested to include 2016 Actuals is shown in DOC IR 2105.01 Attach. The $1.6 million estimate of the revenue requirement impact relies on a number of simplifying assumptions that are identified in DOC IR 2105.01 Attach.

SUPPLEMENTAL RESPONSE (May 23, 2017):

(B) Please refer to DOC IR 2105.01 Attach Supp for both the Total Company impact ($1.6 million) and the MN Jurisdictional impact ($1.36 million).

Witness: Christopher E. Fleege
Response by: Kelly Blindauer
Title: Supervisor Project Management Optimization
Department: Delivery Support Operations
Telephone: 218-355-2487

Estimate of Revenue Requirement Impact of Reduced 2016 Transmission Capital Expenditures

		Adjustment Calculation	Allocator		MN Juris. Adjustment	Comments/Assump ions
A	**Book Basis of Property - Plant**					
	1 12/31/16 Plant In-Service Adj.	(16,400,000)	DPROD	0.843600	(13,835,040)	Decrease in Plant-In-Service per Property Accounting
	2 12/31/17 Plant In-Service Adj.	-	DPROD	0.843600	-	Assumed that all delayed 2016 projects are completed in 2017.
	3 Average Test Year Plant In-Service Adjustment	(8,200,000)	DPROD	0.843600	(6,917,520)	
B	**Book Basis of Property - Depreciation**					
	4 Total Accumulated Depreciation 12/31/16 Adjustment	(205,000)	DSTMPLT	0.843441	(172,905)	Assumed that 2016 Plant-In-Service that was delayed would have been in service for 6 months in 2016; Assumed 40 year book life.
	5 2017 Depreciation Expense Adjustment	(205,000)	DSTMPLT	0.843441	(172,905)	2016 Plant-In-Service would have been in service for all of 2017 now in-service for 6 of 12 months; Assumed 40 year book life.
	6 Total Accumulated Depreciation 12/31/17 Adjustment	(410,000)	DSTMPLT	0.843441	(345,811)	
	7 Average Test Year Accumulated Depreciation Adj.	(307,500)	DSTMPLT	0.843441	(259,358)	
C	**Book Basis of Property - Summary**					
	8 Average Test Year Plant Adjustment	(8,200,000)	DPROD	0.843600	(6,917,520)	
	9 Less: Average Test Year Acc. Depreciation (w/ Adj.)	307,500	DSTMPLT	0.843441	259,358	
	10 Average Test Year Net Plant (w/ Adjustments)	(7,892,500)			(6,658,162)	
D	**Tax Basis of Property**					
	11 Average Test Year Plant (Net of Contra w/ Adjustments)	(8,200,000)	DPROD	0.843600	(6,917,520)	
	12 12/31/16 Accumulated Tax Depreciation Adjustment	(8,507,500)	DSTMPLT	0.843441	(7,175,574)	50% bonus on Plant-in-Service eliminated; Assumed 20-year tax life.
	13 12/31/17 Accumulated Tax Depreciation Adjustment	7,915,542	DSTMPLT	0.843441	6,676,292	50% bonus on Additional Plant-in-Service in 2017, Additional 1st year tax depreciaiton, Less 2nd year tax depreciation.
	14 Average Test Year Accumulated Tax Depreciation Adj.	(295,979)	DSTMPLT	0.843441	(249,641)	
	15 Average Test Year Tax Basis	(7,904,021)			(6,667,879)	
	16 Average Test Year Tax Book Difference Adjustment	11,521			9,717	
	17 Income Tax Rate 1/	41.37%			41.37%	
	18 Average Test Year Acc. Deferred Income Tax Liability Adj.	4,766			4,020	
E	**Revenue Requirements - Return on Rate Base**					
	19 Average Test Year Net Plant	(7,892,500)			(6,658,162)	
	20 Less: Average ADITL - Def Taxes	(4,766)			(4,020)	
	21 Plus: Cash Working Capital	-			-	Assumed no changes in working capital
	22 Average Test Year Rate Base	(7,897,266)			(6,662,182)	
	23 Rate of Return 2/	0.1149			0.1149	
	24 Return on Test Year Average Rate Base	(907,396)			(765,485)	
F	**Revenue Requirements - O&M/Expenses**					
	25 O&M	-			-	Assumed no changes in O&M
	26 A&G	-			-	Assumed no changes in A&G
	27 Total Test Year O & M Adjustment	-			-	
	28 Test Year Depreciation Expense Adjustment	(205,000)	DSTMPLT	0.843441	(172,905)	
	29 Property Tax Adjustment	(492,000)	PROPTAX	0.865899	(426,022)	Assumed Property Tax Rate of 3% of Plant-in-Service 12/31/2016
G	**Total Revenue Requirements**					
	30 Annual Revenue Requirement Adjustment	(1,604,396)			(1,364,412)	

Notes: 1/ Minnesota Composite Income Tax Rate
2/ Minnesota Power's proposed pre-tax rate of return of 11.49%

OAG No. 124

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota	**MPUC Docket No.** E015/GR-16-664
By: Ryan Barlow **Telephone:** (651) 757-1473	**Date of Request:** April 27, 2017 **Due Date:** May 9, 2017

For all responses show amounts for Total Company and the Minnesota retail jurisdiction unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Company response to LPI Information Request 38

Provide an update to the in-service dates to Schedule 1.

Provide this information in Excel format with formulas intact.

RESPONSE:

Please see OAG IR 124.01Attach for updated in-service dates for the Generation capital projects provided in Schedule 1.

As noted in OAG IR 124.01 Attach, the in-service date for 12 capital projects have shifted in service dates. These capital projects are listed below. Reasons for these projects shift in date can be found on OAG IR 124.01 Attach.

Budget Number	Budget Description	Budgeted In-service Date	Updated In-service Date	Reason for In-service Date Change
108924	BEC F C-3 CONVEYOR GEAR BOX REPL	11/30/2017	12/31/2019	See OAG IR 124.01 Attach
108907	BEC-3 MILL OVERHAUL	4/30/2017	6/30/2017	See OAG IR 124.01 Attach
108933	BEC 4 COAL BUNKER	11/15/2017	Postponed	See OAG IR 124.01 Attach

Witness: Joshua J. Skelton
Response by: Rhonda Munger
Title: Budget Analyst-Senior
Department: Generation Operations
Telephone: 218-313-4496

	DIVERTER PIPING			
108849	HREC Replace Wood Shed Auger	10/31/2017	10/31/2018	See OAG IR 124.01 Attach
108854	HREC Replace Metering Bin Screw U3	6/30/2017	6/30/2020	See OAG IR 124.01 Attach
108855	HREC Grate Replacement Unit 3	11/30/2017	4/30/2017	See OAG IR 124.01 Attach
108906	BEC-1 BAGHOUSE BAG REPLACEMENT	4/30/2017	5/30/2017	See OAG IR 124.01 Attach
108908	BEC 4 POST RETROFIT ADDITIONS	12/30/2017	Postponed	See OAG IR 124.01 Attach
108954	BEC F CUSHMAN CART REPLACEMENT	4/30/2017	6/30/2017	See OAG IR 124.01 Attach
108795	Blanchard Gantry Crane Improvements	12/31/2017	12/31/2018	See OAG IR 124.01 Attach
105779	Little Falls Debris Control U 1-4	12/31/2017	Cancelled	See OAG IR 124.01 Attach
108682	Boat for Hydro Maintenance	4/30/2017	5/30/2017	See OAG IR 124.01 Attach

As noted in the table above, the in-service dates for five of these 12 projects have shifted within 2017, the in-service date for the remaining seven projects have shifted outside of 2017. While the in-service dates for these seven projects have shifted outside of 2017, several other capital projects emerged after the creation of the test year budget as necessary to complete within 2017. These projects and their budgets are provided below. A description of the need for each of these projects is provided in OAG 124.01 Attach. It should be noted that the following table does not likely include all new capital projects that will be completed in 2017. Generation will continue to monitor its generation units and operating equipment throughout 2017 and will make all necessary investments to sustain the reliability of its generation assets.

Witness: Joshua J. Skelton
Response by: Rhonda Munger
Title: Budget Analyst-Senior
Department: Generation Operations
Telephone: 218-313-4496

Budget Number	Budget Description	In-service Date	Budget	Need for Project
109537	BEC 4 Stack Extension	11/30/2017	368,004	See OAG IR 124.01 Attach
109327	BEC 4 Condensate Pump Overhaul	3/31/2017	208,259	
109330	BEC F C-14 Chute Fineness Screen Replacement	5/31/2017	144,628	
109633	BEC 3 Main Boiler Feed Pump Overhaul	5/31/2017	367,600	
109482	BEC 3 Elevator Main Hoist and Motor replacement	6/30/2017	60,000	
109348	BEC 12 EDI (electrodeionization) Common Stacks	5/30/2017	61,300	

Witness: Joshua J. Skelton
Response by: Rhonda Munger
Title: Budget Analyst-Senior
Department: Generation Operations
Telephone: 218-313-4496

2017 Generation Capital Additions to Plant

2017 Construction Budget

Expenditure Type Description	Bus Segment Id	Default Plant Account	Major Location Description	**Budget Number**	**Budget Description**	**Eligible for AFDC**	**In Service Date**	**Updated In-Service Date**	**Total**	**Comments**
Additions	100	3110	BOSWELL ENERGY CENTER - COMM	107431	BECF-Rpl BEC3 Tripper Rm Roofs	yes	6/30/2017	6/30/2017	252,900.62	
Additions	100	3110	BOSWELL ENERGY CENTER - COMM	108965	BEC F EMERG. LIGHTING-C 1&2 CONVEYO	no	12/31/2017	12/31/2017	26,862	
Additions	100	3110	BOSWELL ENERGY CENTER - UNIT #3	108991	BEC-3 LOW ROOF SW CORNER OPS	yes	11/30/2017	11/30/2017	61,100.03	
Additions	100	3120	BOSWELL ENERGY CENTER - COMM	108917	BEC F - C-14 CRUSHER REBUILD	no	11/30/2017	11/30/2017	30,786	
Additions	100	3120	BOSWELL ENERGY CENTER - COMM	108923	BEC F - CONVEYOR BELT BLANKET	no	12/31/2017	12/31/2017	55,000	
Additions	100	3120	BOSWELL ENERGY CENTER - COMM	108924	BEC F C-3 CONVEYOR GEAR BOX REPL	no	11/30/2017	12/31/2019	114,104.61	postponed- reassessed the condition of this equipment and immediate replacement is not necessary to be complete in this year, MP will contine to examine condition and complete when necessary
Additions	100	3120	BOSWELL ENERGY CENTER - COMM	108970	BEC F REPL LOAD CENTER #3 TRANSFORM	no	11/30/2017	11/30/2017	85,063	
Additions	100	3120	BOSWELL ENERGY CENTER - COMM	108989	BEC F - VC4 VACUUM SYSTEM PNEUMATIC	yes	8/31/2017	8/31/2017	109,908.25	
Additions	100	3120	BOSWELL ENERGY CENTER - COMM	109020	BEC F SHOP FIRE PROTECTION ADDITION	no	7/1/2017	7/1/2017	87,960	
Additions	100	3120	BOSWELL ENERGY CENTER - COMM	109024	BEC F C-8 SUMP PUMP REPL	no	12/1/2017	12/1/2017	128,099.33	
Additions	100	3120	BOSWELL ENERGY CENTER - COMM	109043	BEC F ELECTRICAL COMPLIANCE	yes	12/31/2017	12/31/2017	186,676.47	
Additions	100	3120	BOSWELL ENERGY CENTER - UNIT #3	108907	BEC-3 MILL OVERHAUL	yes	4/30/2017	6/30/2017	500,002.48	Purchase orders not released as early as originally budgeted
Additions	100	3120	BOSWELL ENERGY CENTER - UNIT #3	108920	BEC-3 COAL FEEDER (YEAR 2 OF 5)	no	10/31/2017	10/31/2017	70,000	
Additions	100	3120	BOSWELL ENERGY CENTER - UNIT #3	108947	BEC-3 BFP RECIRC VALVE	no	5/31/2017	5/31/2017	148,000	
Additions	100	3120	BOSWELL ENERGY CENTER - UNIT #4	108914	BEC 4 BOILER COMPONENT REPLACEMENT	yes	11/30/2017	11/30/2017	643,486.88	
Additions	100	3120	BOSWELL ENERGY CENTER - UNIT #4	108933	BEC 4 COAL BUNKER DIVERTER PIPING	yes	11/15/2017		208,080.85	postponed- reassessed the condition of this equipment and immediate replacement is not necessary to be complete in this year, MP will contine to examine condition and complete when necessary
Additions	100	3120	BOSWELL ENERGY CENTER - UNIT #4	108979	BEC-4 "G" Mill Gearbox Overhaul	yes	10/31/2017	10/31/2017	720,003.20	
Additions	100	3120	BOSWELL ENERGY CENTER - UNIT #4	109002	BEC-4 "A" MBFP Rebuild	no	10/31/2017	10/31/2017	200,000.60	

Additions	100	3120	Hibbard Enegy Center - Location 10:	108849	HREC Replace Wood Shed Auger	yes	10/31/2017	10/31/2018	102,797.70	Project has been postponed due to a reassessment of the condition of this equipment. Based on this assessment it was determiend that an immediate replacement this year is is not necessary but MP will contine to examine condition and complete this replacement whenconditions warrant.
Additions	100	3120	Hibbard Enegy Center - Location 10:	108852	HREC Wood/Coal Feeder U3 & U4	yes	10/31/2017	10/31/2017	454,957.43	
Additions	100	3120	Hibbard Enegy Center - Location 10:	108854	HREC Replace Metering Bin Screw U3	yes	6/30/2017	6/30/2020	246,435.47	Project has been postponed due to a reassessment of the condition of this equipment. Based on this assessment it was determiend that an immediate replacement this year is is not necessary but MP will contine to examine condition and complete this replacement whenconditions warrant.
Additions	100	3120	Hibbard Enegy Center - Location 10:	108855	HREC Grate Replacement Unit 3	yes	11/30/2017	4/30/2017	471,408.03	In-service date moved up to spring outage
Additions	100	3121	BOSWELL ENERGY CENTER - COMM	105318	BECF-U3 Dry Ash Handling Sys Final	yes	12/31/2017	12/31/2017	1,525,676.27	
Additions	100	3121	BOSWELL ENERGY CENTER - COMM	108927	BEC CEMS IT Hardware replacement	no	12/31/2017	12/31/2017	266,914	
Additions	100	3121	BOSWELL ENERGY CENTER - COMM	109025	BEC F U3 ASH SILO OVERHEAD DOORS	no	6/30/2017	6/30/2017	86,764.26	
Additions	100	3121	BOSWELL ENERGY CENTER - UNIT #	108906	BEC-1 BAGHOUSE BAG REPLACEMENT	no	4/30/2017	5/30/2017	400,000	Purchasing decision was delayed which resulted in a delay in the in-service date.
Additions	100	3121	BOSWELL ENERGY CENTER - UNIT #4	108908	BEC 4 POST RETROFIT ADDITIONS	no	12/30/2017		1,200,000	These additions will be evaluated for need once warranty of newly installed emissions equipment has expired
Additions	100	3121	BOSWELL ENERGY CENTER - UNIT #4	108911	BEC 4 BURNER TIP REPLACEMENT	yes	11/30/2017	11/30/2017	322,245.53	
Additions	100	3121	Hibbard Enegy Center - Location 10:	108909	HREC Umbilical Replacement	no	6/30/2017	6/30/2017	74,992.71	
Additions	100	3150	BOSWELL ENERGY CENTER - UNIT #3	108916	BEC-3 DCS FBM MIGRATION	yes	5/31/2017	5/31/2017	484,681	
Additions	100	3150	LASKIN ENERGY CENTER	108748	LEC Station Battery Replacement	no	9/30/2017	9/30/2017	151,000	
Additions	100	3160	BOSWELL ENERGY CENTER - COMM	108951	BEC F SKIDSTEER PURCHASE	no	6/30/2017	6/30/2017	61,782.60	
Additions	100	3160	BOSWELL ENERGY CENTER - COMM	108954	BEC F CUSHMAN CART REPLACEMENT	no	4/30/2017	6/30/2017	11,461.12	Purchasing decision was delayed which delayed the in-service date.
Additions	100	3160	BOSWELL ENERGY CENTER - COMM	108996	BEC F - INSTALL LADDER D10T #B2005	no	9/30/2017	9/30/2017	37,606.80	
Additions	100	3310	BLANCHARD HE STATION - PROJECT	108795	Blanchard Gantry Crane Improvements	yes	12/31/2017	12/31/2018	299,887.38	This project requires extensive design work and requires FERC approval for final design which is taking longer than anticipated to obtain.
Additions	100	3310	LITTLE FALLS HE STATION - PROJECT	107559	Little Falls Hydro Tuck Pointing	yes	12/31/2017	12/31/2017	215,422.09	
Additions	100	3310	THOMSON HE STATION - PROJECT 2	106779	THM Rpl Roofs Brick Storage Bldgs	no	12/31/2017	12/31/2017	56,059.79	
Additions	100	3310	THOMSON HE STATION - PROJECT 2	108902	Thomson- Warehouse Windows & Doors	no	12/31/2017	12/31/2017	89,659.50	
Additions	100	3310	THOMSON HE STATION - PROJECT 2	108910	Thomson-West Side Bldg Tuck Pointin	yes	12/31/2017	12/31/2017	249,730.03	
Additions	100	3310	THOMSON HE STATION - PROJECT 2	108912	Thomson Cross Receiver Wall Rehab	no	12/31/2017	12/31/2017	99,659.50	
Additions	100	3310	WINTON HE STATION - PROJECT 46	108897	Winton-Rehab Caretaker House	no	12/31/2017	12/31/2017	30,127.60	
Additions	100	3312	ISLAND LAKE RESERVOIR - PROJECT	108048	Hydro Recreation Blanket	no	12/31/2017	12/31/2017	30,000	
Additions	100	3312	THOMSON HE STATION - PROJECT 2	108047	Hydro Rec & Erosion Control	no	12/31/2017	12/31/2017	75,000.25	
Additions	100	3320	BLANCHARD HE STATION - PROJECT	108089	BLA Replace Gate Hoist Car	yes	12/31/2017	12/31/2017	365,465.28	
Additions	100	3320	ISLAND LAKE RESERVOIR - PROJECT	108539	Island Lake Main Dam Stability	no	12/31/2017	12/31/2017	141,150.12	
Additions	100	3320	ISLAND LAKE RESERVOIR - PROJECT	108856	Island Lake Park Shoreline Restore	no	12/31/2017	12/31/2017	70,000	
Additions	100	3320	KNIFE FALLS HE STATION - PROJECT	106340	Knife Fls New Headgates_Hoist Sys	yes	12/31/2017	12/31/2017	229,508.49	
Additions	100	3320	LITTLE FALLS HE STATION - PROJECT	105779	Little Falls Debris Control U 1-4	yes	12/31/2017		131,784.49	A less expensive maintenace option pursued instead of the proposed project.

Additions	100	3320	LITTLE FALLS HE STATION - PROJECT	107061	LFL Replace Tainter Gates 1 & 2	yes	12/31/2017	12/31/2017	2,159,513.11	
Additions	100	3320	LITTLE FALLS HE STATION - PROJECT	107712	LFL Replace Tainter Gate 5	yes	12/31/2017	12/31/2017	1,507,254.75	
Additions	100	3320	LITTLE FALLS HE STATION - PROJECT	108797	Little Falls Bank Stabilization	no	12/31/2017	12/31/2017	50,055.20	
Additions	100	3320	LITTLE FALLS HE STATION - PROJECT	108802	Little Falls Head Gates U1-4	yes	12/31/2017	12/31/2017	600,294.59	
Additions	100	3320	SYLVAN HE STATION - PROJECT NO :	105737	Sylvan Increase Spill Capacity	yes	12/31/2017	12/31/2017	1,400,480.31	
Additions	100	3320	THOMSON HE STATION - PROJECT 2	106069	Thomson Replace/Refurbish Dam 6	yes	12/31/2017	12/31/2017	953,473.20	
Additions	100	3320	THOMSON HE STATION - PROJECT 2	106794	Thomson Spill Capacity	yes	12/31/2017	12/31/2017	6,281,160.37	
Additions	100	3320	THOMSON HE STATION - PROJECT 2	107434	THM Replace Bridge to Station	yes	12/31/2017	12/31/2017	268,613.85	
Additions	100	3320	THOMSON HE STATION - PROJECT 2	108043	Hydro Ops Concrete Dam Refurb	no	12/31/2017	12/31/2017	1,326,749.45	
Additions	100	3320	WINTON HE STATION - PROJECT 469	106338	Winton Refurbish Unit 2 Head Gates	yes	12/31/2017	12/31/2017	221,788.03	
Additions	100	3340	THOMSON HE STATION - PROJECT 2	108780	Thomson Control System Upgrade	yes	12/31/2017	12/31/2017	299,945.73	
Additions	100	3350	THOMSON HE STATION - PROJECT 2	108682	Boat for Hydro Maintenance	no	4/30/2017	5/30/2017	20,000	Purchase orders not released as early as originally budgeted and therefore the in-service date was delayed.
Additions	100	3410	BISON WIND GENERATION 1A: 0195	108766	2017 Bison Units of Property	no	12/31/2017	12/31/2017	200,000	
Additions	100	3460	TACONITE RIDGE ENERGY CENTER	108781	TREC-Gen Units	no	12/31/2017	12/31/2017	75,000	
Additions	100	3900	BOULDER LAKE RESERVOIR - PROJE(	108764	Security Cameras at Boulder Lake	no	12/31/2017	12/31/2017	29,996.52	
Additions	100	3900	FISH LAKE RESERVOIR - PROJECT 23(	108756	Security Cameras at Fish Lake	no	12/31/2017	12/31/2017	60,638	
Additions	100	3911	BOSWELL ENERGY CENTER - COMM	109015	BEC F FOXBORO OPERATOR STATION/SERV	yes	11/1/2017	11/1/2017	122,177.69	
Additions	100	3970	BUILDING	108716	2017 Generation Transport drawdown	no	12/31/2017	12/31/2017	150,000	
Additions	100	3970	BUILDING	108717	2017 Generation Network drawdown	no	12/31/2017	12/31/2017	285,000	
Additions	100	3970	BUILDING	108718	2017 Generation Telephony drawdown	no	12/31/2017	12/31/2017	100,000	
Total	Total	Total	Total	Total	Total	Total	**Total**		**27,722,352.56**	
							Per Rate Case Schedules			
							Function A100		9,526,757.24	
							Function B100		16,931,632.99	
							Function B200		241,150.12	
							Function E400		747,812.21	
							Function H100		275,000.00	
									27,722,352.56	
				Projects from above total moved out of 2017					2,303,090.50	
				Unbudgeted Projects moved in to service 2017						
				109537	BEC 4 Stack Extension	yes		11/30/2017	368,004	This project involves extending the stack for BEC4. This extension is needed due to safety hazard of ice on stack falling to the ground below.
				109327	BEC 4 Condensate Pump Overhaul	no		3/31/2017	208,259	This project involves the replacement and repair of damaged casing and impellor.
				109330	BEC F C-14 Chute Fineness Screen Replacem	no		5/31/2017	144,628	This project involves the replacement of screens. The current holes in these screens allow too large of coal chunks to pass to pulverizers.
				109633	BEC 3 Main Boiler Feed Pump Overhaul	no		5/31/2017	367,600	The Unit 3 main boiler feed pump failed in service causing an immediate reduction in output. The boiler feed pump consists of a barrel assembly and various other items such as seals, bearings, fasteners, o-rings etc. When a Boiler Feed Pump fails, the entire barrelmust be replaced.

109482	BEC 3 Elevator Main Hoist and Motor replace	no	6/30/2017	60,000	The existing hoist was flagged by elevator inspection in 2016 could be tagged out of service by inspector until repaired at any time. The existing hoist is obsolete and needs to be updated with new model. The elevator is critical to plant operations at Unit 3.
109348	BEC 12 EDI (electrodeionization) Common Stá	no	5/30/2017	61,300	This proejct involves replacement of worn modulesthat provide makeup water that is critical to the water blending at the Unit 1&2 boiler.
				1,209,791	

OAG No. 127

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota	**MPUC Docket No.**	E015/GR-16-664

By:	Ian Dobson	**Date of Request:**	April 28, 2017
Telephone:	(651) 757-1432	**Due Date:**	May 10, 2017

For all responses show amounts for Total Company and the Minnesota retail jurisdiction unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Company response to OAG IR 1148

In response to OAG IR 1148, MP states: "To clarify, as described in pages 14-24 of Company witness Herbert G. Minke's Direct Testimony, Minnesota Power is requesting in this proceeding that the life of all BEC Units – Boswell Units 1&2, Unit 3, Unit 4, and the Boswell Common Facilities-be consolidated into one remaining life and be extended until 2050. This request relates to establishing the remaining useful life for cost recovery purposes, and is not meant to change the operational life or lives of BEC."

Confirm that MP's proposal is to separate the "cost recovery" period for depreciation expense for the BEC Units (specified above) from the operational or physical life period of these BEC units.

In the alternative, is MP proposing that the operational or probable service life of any of the BEC Units be extended to 2050?

RESPONSE:
Yes, Minnesota Power's proposal is to separate the cost recovery period for depreciation expense for the BEC units from the operational life of these units. Minnesota Power's response to OAG IR 303 provides additional information on the distinction between remaining life for cost recovery and operational lives for BEC units. While the Direct Testimony of Company witness Mr. Herbert G. Minke, III asserts that BEC units may physically be operated until 2050, the Company is not proposing any changes to the operational or probable service lives of BEC units as part of this rate review proceeding. We expect decisions about the future operations of BEC units to be made in other regulatory proceedings, such as future Integrate Resource Planning dockets.

Witness:	Herbert G. Minke, III
Response by:	Susan Ludwig
Title:	Policy Manager
Department:	Regulatory Affairs
Telephone:	218-355-3586

OAG No. 907

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota		**MPUC Docket No.**	E015/GR-16-664
By:	Ryan Barlow	**Date of Request:**	December 2, 2016
Telephone:	(651) 757-1432	**Due Date:**	December 14, 2016

For all responses show amounts for Total Company and the Minnesota retail jurisdiction unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Minke at 11

Please describe MP's current plan for the future retirement of BEC 3 and BEC 4, with Reference: to the current approved remaining life for those units.

RESPONSE:

Minnesota Power has not made any plans for the future retirement of BEC 3 and BEC 4 and communicates its plans on future operations as part of its Integrated Resource Plans filed under Minn. Stat. § 216B.2422.

Witness: Herbert G. Minke, III
Response by: Stewart J. Shimmin
Title: Supervisor, Revenue Requirements
Department: Rates
Telephone: (218) 355-3562

OAG No. 908

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota		**MPUC Docket No.**	E015/GR-16-664
By:	Ryan Barlow	**Date of Request:**	December 2, 2016
Telephone:	(651) 757-1432	**Due Date:**	December 14, 2016

For all responses show amounts for Total Company and the Minnesota retail jurisdiction unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Minke at 11

Identify any orders MP is aware of in which the Commission has authorized recovery of costs for electric generation units after their retirement.

RESPONSE:

Minnesota Power has not done an exhaustive search, but is currently not aware of any MPUC orders that have authorized recovery of costs for electric generation units after their retirement. Minn. Stat. § 216B.16, subd. 6, which specifically authorizes recovery for electric generation units after their retirement, was enacted in 2015 and was not effective until July 1, 2015. See Laws 2015, 1st Sp., c. 1, art. 3, §§ 17 to 19, eff. July 1, 2015.

Witness:	Herbert G. Minke, III
Response by:	David R. Moeller
Title:	Senior Attorney
Department:	Legal Services
Telephone:	218-723-3963

OAG No. 1158

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota	**MPUC Docket No.** E015/GR-16-664
By: Ryan Barlow **Telephone:** (651) 757-1473	**Date of Request:** March 29, 2017 **Due Date:** April 10, 2017

For all responses show amounts for Total Company and the Minnesota retail jurisdiction unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Provide the following information:

1. Identify the estimated removal cost of each of the BEC investments at the end of their remaining life; and
2. Calculate the accumulated removal dollars that would be available at the end of their remaining lives if the depreciation rates are extended to 2050 as requested by MP.

RESPONSE:

1. The estimated removal/decommissioning costs (demolition costs less scrap value) of each of the BEC investments at the end of their remaining life used in the 2017 budget used in the 2017 test year are below:

   Boswell Unit 1 $7,253,145 (MP Ownership 100%)
   Boswell Unit 2 $7,334,379 (MP Ownership 100%)
   Boswell Unit 3 $35,525,172 (MP Ownership 100%)
   Boswell Unit 4 - Total $56,270,964 – MP Ownership (80%) $45,016,771
   Boswell Common – Total $8,661,340 – MP Ownership (89.54%) $7,755,364
   Grant Total $115,045,000 – Grand Total MP Ownership $102,884,831

Witness:	Joshua J. Skelton
Response by:	Debbie Davey
Title:	Supervisor, Accounting
Department:	Accounting
Telephone:	218-355-3714

The estimated removal/decommissioning costs (demolition costs less scrap value) of each of the BEC investments at the end of their remaining life used in Minnesota Power's 2017 Annual Remaining Life Depreciation Petition are below:

Boswell Unit 1 $7,252,055 (MP Ownership 100%)
Boswell Unit 2 $7,252,055 (MP Ownership 100%)
Boswell Unit 3 $36,679,703 (MP Ownership 100%)
Boswell Unit 4 - Total $55,625,143 – MP Ownership (80%) $44,500,114
Boswell Common – Total $8,666,044 – MP Ownership (89.54%) $7,759,576
Grant Total $114,475,000 – Grand Total MP Ownership $102,443,503

2. The estimated removal costs in accumulated depreciation if the depreciation rates are extended to 2050 as requested by Minnesota Power would be the above amounts for MP Ownership of $102,884,831. However, Minnesota Power updates the removal/decommissioning cost estimates at least every five years to keep estimates in line with actual costs to remove/decommission, so the estimated removal/decommissioning costs would likely change between now and 2050.

Witness: Joshua J. Skelton
Response by: Debbie Davey
Title: Supervisor, Accounting
Department: Accounting
Telephone: 218-355-3714

OAG No. 1158.1

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota		**MPUC Docket No.**	E015/GR-16-664
By:	Ryan Barlow	**Date of Request:**	April 21, 2017
Telephone:	(651) 757-1473	**Due Date:**	May 3, 2017

For all responses show amounts for Total Company and the Minnesota retail jurisdiction unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: OAG IR 1158

OAG IR 1158 asked the Company to "Calculate the accumulated removal dollars that would be available at the end of [the BEC investments'] remaining lives if the depreciation rates are extended to 2050 as requested by MP." The Company's response did not address the timing question the OAG is seeking information about.

Please answer the following questions.

1. Would MP's proposal to extend the cost recovery for the depreciation expense for the BEC investments until 2050 also extend the recovery of removal expense until 2050? Provide a complete explanation as to how MP proposes to handle removal expenses under its proposal.

2. If recovery of removal expense is extended until 2050, calculate the accumulated removal dollars that would be available for BEC 3 in 2034 and BEC 4 in 2035.

RESPONSE:

1. Yes, Minnesota Power's proposal to extend the cost recovery for the depreciation expense for the BEC investments until 2050 will also extend the recovery of removal expense until 2050.

Witness:	Joshua J. Skelton
Response by:	Debbie Davey
Title:	Supervisor, Accounting
Department:	Accounting
Telephone:	218-355-3714

Removal costs incurred are debited to accumulated depreciation expense.

Minnesota Power is requesting that BEC be treated as one unit for depreciation and have one remaining life extended to 2050. If BEC is treated as one unit, the recovery of the removal expense to decommission all of BEC would be recovered through 2050.

Minnesota Power has not determined when any of the units will be decommissioned. The plan is to retire BEC 1&2 at the end of 2018, but at this time Minnesota Power has not decided when the units will be decommissioned. The environmental retrofit of BEC4 and a major environmental upgraded at BEC3 are the primary drivers behind the ability of BEC to be able to operate until 2050. Minnesota Power has no plans to decommission BEC 3 in 2034 or BEC 4 in 2035.

2. If recovery of removal expense is extended until 2050, the total estimated accumulated removal dollars, assuming no changes, that would be available for BEC 3 in 2034 would be $23,194,000 and $29,192,000 for BEC 4 in 2035.

   Minnesota Power has no plans to decommission BEC 3 in 2034 or BEC 4 in 2035. Also, Minnesota Power updates the removal/decommissioning cost estimates at least every five years to keep estimates in line with actual costs to remove/decommission, so the estimated removal/decommissioning costs would likely change between now and 2050.

Witness	Joshua J. Skelton
Response by:	Debbie Davey
Title:	Supervisor, Accounting
Department:	Accounting
Telephone:	218-355-3714

OAG No. 1159

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota	**MPUC Docket No.**	E015/GR-16-664
By: Ryan Barlow **Telephone:** (651) 757-1473	**Date of Request:** **Due Date:**	March 29, 2017 April 10, 2017

For all responses show amounts for Total Company and the Minnesota retail jurisdiction unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Provide the following information:

1. Identify the estimated removal costs for the BEC investments if BEC 3 and 4 are operated past their currently established remaining life.

2. If BEC 3 and 4 are operated past 2034 and 2035, would removal costs increase over time? What would the removal costs be in 2040, 2045, and 2050? Produce all documents and analysis possessed by MP that is relevant to future removal costs for the BEC investments.

RESPONSE:

1. When removal/decommissioning cost estimates are determined, the estimated removal/decommissioning cost estimates are presented in current dollars. Therefore, there would be no change to the estimated removal costs for the BEC investments set forth in response to OAG IR 1158 due to BEC 3 and 4 being operated past their currently established remaining life. Minnesota Power updates the removal/decommissioning cost estimates at least every five years to keep estimates in line with actual costs to remove/decommission.
2. As noted above, when removal/decommissioning cost estimates are commissioned by Minnesota Power the estimated removal/decommissioning cost estimates are presented in current dollars. Therefore, Minnesota Power does not have any changes to the estimates for removal costs set forth in response to OAG IR 1158 due to the date for removal/decommissioning being extended. Please see OAG IR 1159.01 Attach for the latest removal/decommissioning cost estimate completed for Minnesota Power by Burns and McDonnell used by Minnesota Power in its 2017 Remaining Life Depreciation Petition filed February 1, 2017.

Witness:	Joshua J. Skelton
Response by:	Debbie Davey
Title:	Supervisor, Accounting
Department:	Accounting
Telephone:	218-355-3714

Site Decommissioning Study 2015

Minnesota Power

Project No. 68913

Revised 12/23/2015

Site Decommissioning Study 2015

prepared for

Minnesota Power
Duluth, Minnesota

Project No. 68913

Revised 12/23/2015

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

TABLE OF CONTENTS

Page No.

LIST OF TABLES

Page No.

LIST OF FIGURES

Page No.

LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
ACM	Asbestos containing material
BEC	Boswell Energy Center
BMcD	Burns & McDonnell Engineering Company, Inc.
BOP	Balance-of-Plant
CCOFA	Close-coupled Over-fire Air
F	Fahrenheit
Facilities	Collectively refers to the coal plants and wind farms evaluated in this report.
FD	Forced draft
ID	Induced draft
kV	Kilovolt
lbs/hr	Pounds per hour
LNB	Low NO_x Burner
MP	Minnesota Power
MW	Megawatt
NO_x	Mono-nitrogen oxide
O&M	Operations and Maintenance
OFA	Over-fire Air
PCB	Polychlorinated biphenyl
Plants	Collectively refers to the coal plants and wind farms evaluated in this report.
PRB	Powder River Basin
Psig	Pounds per square inch gage
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur dioxide

Abbreviation	Term/Phrase/Name
SOFA	Separated Over-fire Air
STG	Steam turbine generator
Study	This Site Decommissioning Study
WLF OFGD	Wet Limestone Forced Oxidation Flue Gas Desulfurization

1.0 EXECUTIVE SUMMARY

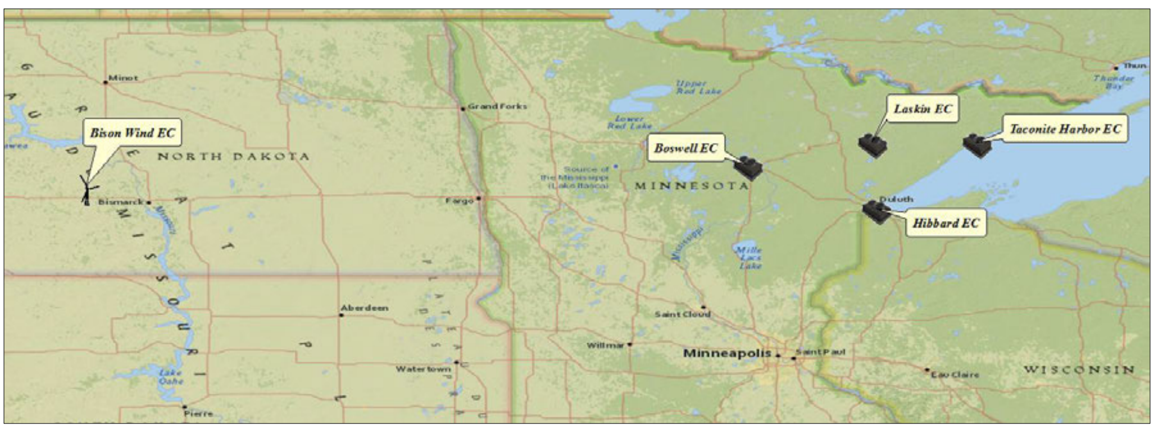
1.1 Study Objective

Burns & McDonnell Engineering Company, Inc. was retained by Minnesota Power to conduct a Site Decommissioning Study for five (5) Minnesota Power facilities, which serves as an update to the 2013 decommissioning study prepared by Burns & McDonnell. The purpose of the Study was to review the facilities and to make a recommendation to MP regarding the total cost to dismantle the facilities and return it to a condition suitable for redevelopment.

1.2 Project Descriptions

The Study evaluated the cost for five (5) facilities owned by Minnesota Power including four (4) coal plants and one (1) wind farm. Figure 1.1 shows the locations of each of the facilities included in this Study. Following the figure is a brief description of each of the Plants.

Figure 1.1: General Plant Locations



Boswell Energy Center: Located in Cohasset, Minnesota and consists of four (4) units, all of which are coal fired steam generators with combined turbine generators. BEC was first in operation in 1958 with an original rating of 75 MW. As additional units were installed over time (commissioned in 1973 and 1980), BEC's capacity has increased to a gross of 1110 MW with units 3 and 4 capable of generating 375 MW and 585 MW of gross capacity (or net of 350 MW and 537 MW), respectively.

Table 1-1: Site Decommissioning Cost Estimate (2015$)

Asset	Demolition Cost	Credits	Net Project Cost	Project Duration
Boswell Energy Center	$124,392,000	($9,917,000)	$114,475,000	18 to 20 months

The total project costs presented above include the costs to return the site to a condition compatible with the surrounding land, similar to the conditions that existed before development of the Plant including any necessary costs for imported topsoil, seed, and fertilizer at the site. Further, these estimates include costs to dismantle the power generating equipment and BOP facilities owned by MP.

1.4 Statement of Limitations

In preparation of this Study, BMcD has relied upon information provided by MP. While BMcD has no reason to believe that the information provided, and upon which BMcD has relied, is inaccurate or incomplete in any material respect, BMcD has not independently verified such information and cannot guarantee its accuracy or completeness.

BMcD's estimates and projections of demolition costs are based on experience, qualifications and judgment. Since BMcD has no control over weather, cost and availability of labor, material and equipment, labor productivity, contractors' procedures and methods, unavoidable delays, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding, market conditions, or other factors affecting such estimates or projections, BMcD does not guarantee the accuracy of its estimates or predictions.

BMcD's estimates and projections of costs do not include allowances for unforeseen environmental liabilities associated with unexpected environmental contamination due to events not considered part of normal operations, such as fuel tank ruptures, oil spills, etc. Estimates also do not include allowances for environmental remediation associated with changes in classification of hazardous materials.

2.0 INTRODUCTION

2.1 Study Overview

Burns & McDonnell Engineering Company, Inc. (“BMcD”) was retained by Minnesota Power (“MP”) to conduct a Site Decommissioning Study (“Study”) for five (5) Minnesota Power facilities (collectively called “Facilities” or “Plants”), which serves as an update to the 2013 decommissioning study prepared by Burns & McDonnell. The purpose of the Study was to review the Facilities and to make a recommendation to MP regarding the total cost to dismantle the Facilities and return them to a condition suitable for redevelopment.

2.2 Organization of Report

This report is organized into several separate chapters and supporting appendices. These individual sections are listed below, along with a brief description of their contents.

Section 1.0 - Executive Summary: An executive summary of the Study.

Section 2.0 - Introduction: A description of the Study’s objectives and the structure of this report.

Section 3.0 - Site Descriptions: An overview of each site location and noteworthy characteristics of each Plant.

Section 4.0 - Site Demolition Evaluation: Descriptions of both the general assumptions and site specific assumption used for evaluating the cost for each Plant.

Section 5.0 - Results: Summary of the estimated cost of decommissioning each of the Plants evaluated in this Study.

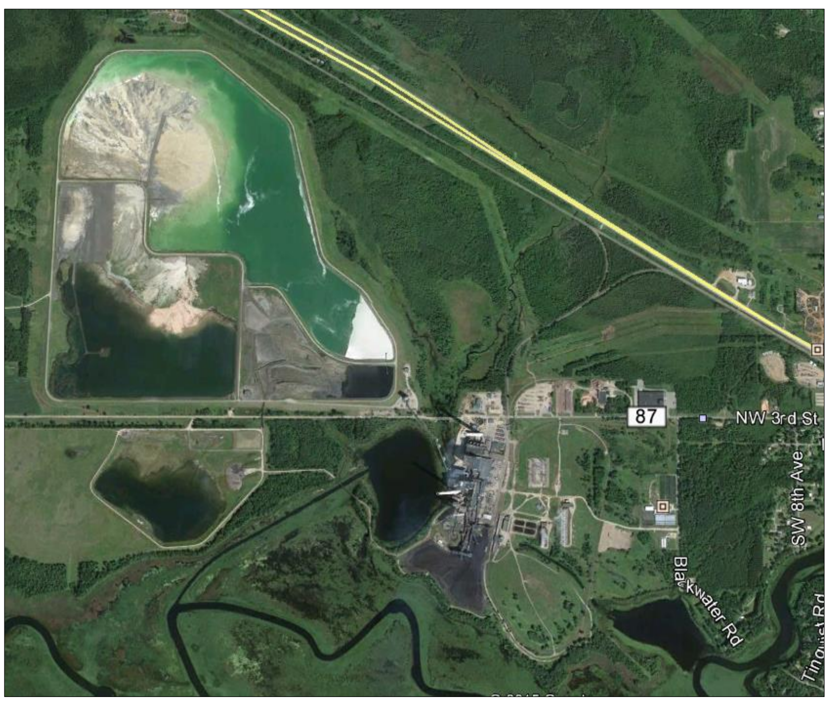
3.0 SITE DESCRIPTIONS

The following sections provide a general description of each facility evaluated in this Study.

3.1 Boswell Energy Center

The Boswell Energy Center ("BEC") is located in Cohasset, Minnesota and consists of four (4) units, all coal-fired steam generators with turbine generators. Figure 3.1 shows an aerial of BEC. The first two units, Unit 1 and Unit 2, were commissioned in 1958 and 1960, respectively. These two units are rated at 69 megawatts ("MW") (net) and 75 MW (gross) each and consist of pulverized coal-fired Riley-Stoker Wall-Fired Steam Generators. Boswell Units 1 and 2 currently employ low mono-nitrogen oxides ("NO_x") burners and Selective Non-Catalytic Reduction ("SNCR") system for NO_x control and a fabric filter for particulate control. No sulfur dioxide ("SO_2") control is currently installed at these units. Unit 1 and Unit 2 utilize once-through cooling drawing water from the nearby lake.

Figure 3.1: BEC Site Aerial



The third unit, Unit 3, at BEC was commissioned in 1973 and includes a pulverized coal-fired Combustion Engineering Tangentially-Fired Steam Generator, with a rated power output of 350 MW (net) and 375 MW (gross). In 2009, air quality control systems were installed to control NO_x, SO_2, particulates, and mercury emissions. During this retrofit, Low NO_x Burners ("LNBs"), Over-fire Air ("OFA") system, and Selective Catalytic Reduction ("SCR") using ammonia were installed to reduce NO_x

emissions. To reduce SO_2 emissions, the unit was equipped with a Wet Limestone Forced Oxidation Flue Gas Desulfurization ("WLF OFGD") system, which utilizes dry ground limestone as reagent. Additionally, a Fabric Filter and an Activated Carbon Injection System were installed to collect fly ash and control mercury emissions, respectively. The fly ash collected by the Fabric Filter is conditioned and disposed on-site in one of the ash ponds. The unit also utilizes a wet cooling tower to reject waste heat into the atmosphere.

The fourth unit, Unit 4, was commissioned in 1980 and includes a pulverized coal-fired Combustion Engineering Tangentially-Fired Steam Generator (similar to Unit 3) with a rated power output of 537 MW (net) and 585 MW (gross). This unit currently employs low NO_x burners and close-coupled Over-fire Air ("CCOFA") for NO_x control, a venturi scrubber for particulate control, and a spray tower absorber for SO_2 control. A small portion of the flue gas (approximately 2 to 5 percent) bypasses the venturi scrubber and spray tower absorber and is treated by an Electro Static Precipitator for particulate control before being blended with the remainder of the flue gas. Once blended, the flue gas is recycled to reheat the flue gas treated by the venturi scrubber and spray tower absorber. The unit also utilizes a wet cooling tower to reject waste heat into the atmosphere.

Boswell has recently made modifications to the air quality control system by adding a dry scrubber and baghouse to be meshed into the exhaust of the boiler units. These new additions as well as associated equipment were included in the decommissioning estimate.

4.0 SITE DEMOLITION EVALUATION

Burns & McDonnell has prepared dismantlement estimates for the five (5) facilities. When MP determines that the site should be retired, the above grade equipment and steel structures are assumed to have sufficient scrap value to a salvage contractor to offset a portion of the site dismantlement costs. However, MP will incur costs of dismantlement of the Plants and restoration of the sites to the extent that those costs exceed the salvage value of equipment and bulk steel.

The site demolition cost includes the cost to return the site to a condition compatible with the surrounding land, similar to the conditions that existed before development of the Plants. The site will be seeded and restored to green space. Included are the costs to dismantle all of the assets owned by MP at the site, including power generating equipment and balance-of-plant ("BOP") facilities.

The site demolition costs were developed using information provided by MP, and in-house data Burns & McDonnell has collected from previous project experience. Burns & McDonnell estimated quantities for equipment based on a visual inspection of the facilities, combined with Burns & McDonnell's in house database of plant equipment quantities, and Burns & McDonnell's professional judgment and MP provided drawings. This resulted in an estimate of quantities for the tasks required to be performed for each dismantlement effort.

Current market pricing for man-hour rates and unit pricing were then developed for each task. The man-hour rates and unit pricing were developed for the site based on the labor rates, equipment costs, and disposal costs specific to the area in which the work is to be performed. These rates were applied to the quantities for the Plant to determine the total cost of dismantlement for each site.

4.1 General Decommissioning Assumptions

The following general assumptions were made as the basis for all the cost estimates:

1. Above grade structures and buildings are included for demolition, unless otherwise noted herein.
2. Estimates include the demolition of onsite buildings including administration buildings, maintenance buildings, warehouses, storage buildings, and any other ancillary buildings. Any spare parts, tools, inventory, or equipment in the buildings will be transferred to another facility or sold prior to decommissioning activities commencing, the value of which is excluded from the estimates.
3. Facilities will be decommissioned to zero generating output. Existing utilities will remain in place for use by the contractor for the duration of these demolition activities.

4. Work will take place in the most cost efficient method.
5. Transmission switchyards and substations within the boundaries of the plant are not part of the demolition scope. The main step-up transformer(s) at the substation is assumed to be removed, but the transmission infrastructure is assumed to remain operational for support of the transmission system.
6. Step up transformers, auxiliary transformers, and spare transformers are included for removal and scrap value in the estimate.
7. No environmental costs have been included to address site clean-up of contaminated soils, hazardous materials, or other conditions present on-site having a negative environmental impact, other than those specifically listed in these assumptions. No allowances are included for unforeseen environmental remediation activities.
8. Handling and disposal of hazardous material will be performed in compliance with the approved methods of MP and governing agencies.
9. Site areas will be graded to achieve suitable site drainage to natural drainage patterns, but grading will be minimized to the extent possible.
10. Major equipment, electrical cabling, and structural steel are included for scrap value. All other demolished materials are considered debris.
11. Credits for salvage value are based on scrap value alone. Resale of equipment and materials is not included.
12. Labor costs are based on a regular forty (40)-hour workweek without overtime.
13. Soil testing and any other on-site testing has not been conducted for this study.
14. Disturbed site areas will be seeded after they are graded to provide suitable ground cover to prevent soil erosion.
15. Estimates are in 2015 dollars and excludes escalation.
16. Project indirects are included at ten (10) percent for field overhead, three (3) percent for home office costs, and ten (10) percent for profit on both labor and material costs.
17. A ten (10) percent contingency was included on the direct costs in the estimates to cover unknowns as well as owner indirects.
18. Market conditions may result in cost variations at the time of contract execution.

4.2 General and Site Specific Assumptions for Coal Plants

In addition to the general decommissioning assumptions stated in Section 4.1, the following general decommissioning assumptions were made for the coal based Plants:

1. Abatement of asbestos and arsenic in the boiler refractory (where applicable) will precede any other demolition work. After final air quality clearances have been reached, demolition can proceed.
2. Removal of asbestos will be done in accordance with any and all applicable Federal, State and Local laws, rules, and regulations.
3. The estimate includes an allowance for abatement of asbestos containing material ("ACM"), unless otherwise stated.
4. Equipment and structures covered with lead-based paint are assumed to be removed and handled by OSHA certified personnel. The lead-based paint is assumed to be abated by the scrap dealer upon recycling.
5. Asbestos costs are based on material estimates included in surveys provided by MP.
6. MP will remove all burnable coal, fuel oil, and chemicals prior to commencement of demolition activities.
7. Coal pile will be closed by removing 6-inches of material for offsite disposal as a non-hazardous waste, backfilling with clean fill, covering with 6-inches of topsoil and hydroseeded to establish vegetation.
8. If present, all polychlorinated biphenyl ("PCB") oil will be removed and disposed of properly.
9. Landfill dikes will be removed and re-graded with the dike material used as fill.
10. All existing basements will be used to bury non-hazardous debris, with the exception of the Hibbard Renewable Energy Center. Concrete in trenches and basements will be perforated to create drainage.
11. Structures at grade and above will be demolished. All structures below grade will be abandoned in-place unless deemed hazardous by MP or otherwise stated in the assumptions as being demolished.
12. Costs for offsite disposal are included for materials in excess of the onsite inert debris disposal capacity. With the exception of the Hibbard Renewable Energy Center site, concrete, masonry, and bricks are assumed to be disposed in the on-site landfill.
13. Valuation and sale of land and all replacement generation costs are excluded from this scope.
14. Sewers, catch basins, and ducts will be collapsed to two (2) feet below grade, filled and sealed on the upstream side. Horizontal runs will be abandoned in place after being closed.
15. Underground piping will be abandoned in place if it is less than four (4) feet in diameter. Circulating water pipes will be capped, have the tops broken up, and backfilled the pipe hollow with on-site soil.

16. Intake and discharge structures that will no longer serve a purpose after station operation will be filled and closed unless otherwise noted in the site specific assumptions. Equipment and structures above the seawall will be removed.
17. Existing sheet piling along the plant property shorelines to the natural bodies of water will remain in place.
18. Crushed rock is assumed to be disposed of on-site by using it for clean fill, disposed in the on-site landfill, or will be recycled by the demolition contractor for beneficial use.
19. Costs are included to clean out the fuel oil tanks and to remove the soil within the immediate vicinity of the tanks to account for the potential for this soil to be contaminated during normal operations.
20. Scrap value of steel is included at $235 per ton.
21. Scrap value of copper is included at $2.35 per pound.

4.2.1 Boswell Energy Center

The following assumptions were made for the BEC facilities are assumed to be demolished:

1. Fly ash, bottom ash, and sludge pond closure estimates for all BEC units were estimated by Barr Engineering Company. These estimates exclude the cost for onsite pond maintenance building and other miscellaneous pond infrastructures. For assumptions stated by BARR Engineering Company see Appendix C. These estimates were not independently verified by BMcD.
2. Unit 1, Unit 2, Unit 3, and Unit 4 Power blocks, including boilers, turbines and turbine hall, fan room, diesel-fired generator set, coal bunkers, fly and bottom ash silos, precipitators, administrative building, and stacks are included in the decommissioning.
3. The SNCR system and a SCR system will be removed in conjunction with Unit 2 and Unit 3, respectively.
4. BOP buildings and facilities such as the absorber building, warehouse, low point sump building, water treatment buildings and clarifiers, and storage buildings are included in the decommissioning.
5. Coal handling equipment, coal rotary unloader and indexer, silos, and conveyors will be removed from site.
6. Unit 1 and Unit 2 utilize intake structures connected to Blackwater Lake, including circulating water pumps, which will be removed.
7. The cooling system serving Unit 3 and Unit 4 including cooling towers, tower basins, and circulating water pumps will be removed.
8. Pollution control equipment storage is included in decommission.

9. Concrete foundations and miscellaneous structures will be removed to grade. Foundations and structures below grade will be left in place.
10. The rail and ballast south of Old Highway No. 6, including rail loop, will be removed.

The following BEC-specific assumptions were used as the basis for the cost estimate.

11. Auger cast piles and steel tube piles underneath foundations will remain in place.
12. The sheet piling along the lake shore will remain in place.
13. The 230 kV substation and transmission lines and associated appurtenances are excluded from the decommission estimate.
14. Intake water building foundation will be removed and the excavation filled in with inert demolition material.
15. Water generated during dewatering of the ash ponds will be treated through the onsite water treatment system prior to closure.
16. BEC has recently been retrofitted with a new baghouse, dry scrubber, ash piping, and other associated equipment. A demolition estimate for the new air quality control equipment is included in the decommissioning estimate.

5.0 RESULTS

Table 5-1 presents a summary of the decommissioning costs and the available scrap values for the four (4) coal plants. Because coal plants have additional complexities than that of modern day wind farms, Table A-1 in Appendix A provides a breakdown of the major cost components of the four (4) coal plants evaluated. This breakdown is unique to the coal plants and includes cost for subjects such as asbestos disposal, galbestos disposal, and pond closure.

Table 5-1: Decommissioning Costs for Coal Plants (2015$)

	Costs (2015$)			
Category	**Boswell**			
Mobilization	$150,000			
Demolition & Disposal	$28,824,000			
Asbestos Abatement Allowance	$2,048,000			
Galbestos Removal & Disposal	$691,000			
Other Hazardous Material Disposal	$198,000			
Site Grading & Fill	$1,815,000			
Site Restoration	$102,000			
Landfill and Pond Closure[1]	$77,190,000			
Coal Pile Closure	$2,066,000			
Project Indirects	Included Above			
Project Contingency (10%)	$11,308,000			
Total Project Costs	**$124,392,000**			
Scrap Value	**($9,917,000)**			
Net Project Costs	**$114,475,000**			

[1]Landfill and Pond Closure costs for BEC were provided by BARR Engineering Company (see Appendix C)

The cost estimates for all coal plants assume the steam turbine generators ("STGs") are demolished and scrapped. Should MP decide to salvage the STGs and sell them to a third party, the overall net project costs may decrease by $1 to $2 million per plant depending on the market conditions for used STGs. The demolition costs would increase due to additional cost to remove the STGs properly for reuse; however the additional revenue from selling the STGs would more than offset the additional demolition costs.

APPENDIX A -
PER UNIT BREAKDOWN OF DECOMMISSIONING COST (2015$)

Table A-1: Per Unit Breakdown of Decommissioning Costs (2015$)

	Demolition Costs	Scrap Value	Net Project Costs
Boswell			
Unit 1	$2,374,500	($742,000)	$1,632,500
Unit 2	$2,374,500	($742,000)	$1,632,500
Unit 3	$8,541,000	($3,024,000)	$5,517,000
Unit 4	$10,858,000	($3,539,000)	$7,319,000
Common Area	$9,680,000	($1,870,000)	$7,810,000
Landfill and Pond Closure	$77,190,000	N/A	$77,190,000
Coal Pile Closure	$2,066,000	N/A	$2,066,000
Project Contingency	$11,308,000	N/A	$11,308,000

APPENDIX C -
SUPPLEMENT TO SITE DECOMMISSIONING STUDY BY BARR ENGINEERING COMPANY

Supplement to Site Decommissioning Study

Impoundment and Landfill Infrastructure

Prepared for
Minnesota Power

March 12, 2015

4700 West 77th Street
Minneapolis MN 55435-4803
Phone: 952.832.2600
Fax: 952.832.2601

Supplement to Site Decommissioning Study

March 12, 2015

Contents

List of Tables

List of Attachments

1.0 Plant Infrastructure Descriptions

Minnesota Power (MP) asked Barr Engineering Company (Barr) to prepare estimates of closure costs for certain MP ash and water management infrastructure. This report is intended to supplement a site-wide demolition report by Burns & McDonnell and only considers the costs of the areas described in this report. The following provides a description of the infrastructure considered at each facility.

1.1 Boswell Energy Center

The ash management areas subject to this evaluation include the Old Unit 3 Bottom Ash Pond, the current Units 1-4 Bottom Ash Pond, Unit 3 Fly Ash Pond including the dry disposal area, and Units 1,2,4 Fly Ash and SO2 Sludge Pond. Closure costs were developed for the Old Unit 3 Bottom Ash Pond, the current Units 1-4 Bottom Ash Pond, Unit 3 Fly Ash Pond, and the Units 1,2,4 Fly Ash and SO2 Sludge Pond. Demolition costs for the onsite pond maintenance building and other miscellaneous pond infrastructure were not considered in this evaluation.

2.0 Closure Design Assumptions

The design assumptions for closure at the Boswell Energy Center and the Taconite Harbor Energy center are described in this Section.

2.1 General Closure Assumptions

All Coal Combustion Residual (CCR) units evaluated in this analysis will be closed and/or reclaimed to meet the requirements of state rules and the Environmental Protection Agency (EPA) CCR rule pre-publication draft dated December 19, 2014. Additional closure (final cover) and reclamation detail is included in the following sections.

2.1.1 Final Cover

For purposes of this study and cost estimate, Barr assumed that a MPCA – Industrial Solid Waste Landfill Final Cover design would be used in closing the site surface impoundments and existing landfills. Below are the key design assumptions used in this study:

- MPCA – Industrial Solid Waste Landfill Final Cover Design
    - 40-mil LLDPE geomembrane for cover system hydraulic barrier layer
    - 12-inch-thick drainage layer
    - 12-inch-thick rooting soil layer
    - 6-inch-thick topsoil layer

2.1.2 Reclamation

Reclamation refers to the process of closing cell areas by removing CCR material and reestablishing turf according to applicable Minnesota reclamation requirements. Reclamation is typically cost effective for areas where CCR material depth is minimal and where the CCR material can be relocated onto deeper CCR deposits that will be covered. This consolidation minimizes the area of CCR material requiring final cover. The specific assumptions used in this evaluation are provided below:

- For purposes of this study and cost estimate, all areas where existing CCR deposits are removed will be reclaimed with the following construction activities and typical reclamation section:
    - General site grading
    - 12-inch-thick cover soil layer
    - 6-inch-thick topsoil layer
    - Turf establishment

2.2 Site Specific Closure Assumptions

The following sections describe the site specific closure assumptions for each facility.

2.2.1 Boswell Energy Center

There are four ash management areas that will require closure. These areas include Units 1,2,4 Fly Ash and SO2 Sludge Pond, Unit 3 Fly Ash Pond, the Old Unit 3 Bottom Ash Pond and the Units 1-4 Bottom Ash Pond. Dewatering of the ponds is not considered in this closure study. Each ash management area total acreage, closed acreage, and reclaimed acreage assumption is presented below:

- **Units 1,2,4 Fly Ash and SO2 Sludge Pond:** Total = 292 acres; Closed = 195 acres; Reclaimed = 97 acres
- **Unit 3 Fly Ash Pond:** Total = 197 acres; Closed = 103 acres; Reclaimed = 94 acres
- **Old Unit 3 Bottom Ash Pond:** Total = 74 acres; Closed = 33 acres; Reclaimed = 41 acres
- **Units 1-4 Bottom Ash Pond:** Total = 55 acres; Closed = 0 acres; Reclaimed = 55 acres

The key assumptions that apply to the closure design for this study and cost estimates are provided below:

- The existing impoundment delta slopes for the Unit 3 Fly Ash Pond and Units 1,2,4 Fly Ash and SO2 Sludge Pond cannot be altered significantly by grading. Additional fill placement, assumed to be reclaimed bottom ash, will be required to achieve a final cover slope.
- Approximately 490,000 cubic yards of existing Units 1,2,4 Fly Ash and SO2 Sludge Pond CCR could be consolidated (assumes that ash less than 5 feet deep along the leading edge of the ash delta can be excavated and moved to the top of the ash delta). For purposes of this study, the 2014 Bathymetric Study data was used to estimate ash thickness.
- Approximately 590,000 cubic yards of existing Unit 3 Fly Ash Pond FGD can be consolidated (assumes that FGD solids less than 5 feet deep along the leading edge of the FGD delta can be excavated and moved to the top of the ash delta). For purposes of this study, 2014 bathymetric survey data was used to estimate FGD solids thickness.
- All bottom ash is removed from the Units 1-4 Bottom Ash Pond and used as closure fill in Units 1,2,4 Fly Ash and SO2 Sludge Pond and Unit 3 Fly Ash Pond.
- Approximately 41 acres of the Old Unit 3 Bottom Ash Pond can be reclaimed with bottom ash being used as fill in other pond closure activities.
- No additional geotechnical corrections (e.g., beyond geogrid reinforcing included in Units 1,2,4 Fly Ash and SO2 Sludge Pond closure estimate) are required to the existing ash delta surfaces.

Pond closure items that are not included in this analysis are as follows:

- Demolition costs for the onsite pond maintenance building.
- Demolition costs for other miscellaneous pond infrastructure.

3.0 Estimates of Closure Costs

This Section provides the basis for the cost estimates and summarizes the estimated costs for closure of each of the facilities described above.

3.1 Scope of Estimates

The opinion of probable cost for each facility was developed using information from similar projects and the consulting team's experience and qualifications. The opinion of cost represents the team's best judgment as experienced and qualified professionals familiar with the project, based on project-related information available at this time, available cost information from other projects, and a screening-level design for each alternative. The opinion of probable cost could change as more information becomes available and the level of design detail is advanced. In addition, since the team has no control over the cost of labor, materials, equipment, or services furnished by others, over contractor's methods of determining prices, or over competitive bidding or market conditions, it can be expected that proposals, bids, or actual construction costs will vary from this opinion of probable cost. If a more accurate opinion of probable cost is desired, a more detailed study including a more detailed definition of the closure would be necessary.

Barr's estimates and projections of costs do not include allowances for unforeseen environmental liabilities associated with unexpected environmental contamination due to events not considered part of normal closure activities, such as fuel tank ruptures, oil spills, etc.

3.2 Range of Uncertainty

The anticipated construction cost for closure is based on screening-level design. The opinion of cost should be considered a screening-level, order-of-magnitude estimate that generally corresponds to a Class 5 estimate based on standards established by the Association for the Advancement of Cost Engineering (AACE) and American Society for Testing and Materials (ASTM). A Class 5 cost estimate is characterized by limited project definition (less than 5%), wide-scale use of parametric models (e.g., making extensive use of order-of-magnitude costs from similar projects or proposals) to calculate estimated costs, and high uncertainty. The estimated closure cost is a point estimate within a range of possible costs. The selected accuracy range for these point estimates for closure is -25% to +50%.

3.3 Closure Unit Pricing

Unit pricing for closure costs varied for each energy center. Overall closure costs for Boswell Energy Center were calculated using assumed 2014 dollars unit prices. Overall closure costs for Taconite Harbor Energy Center were calculated using 2014 dollars unit prices information provided in the facility Permit Application.

3.4 Site Cost Estimates

This section includes the site closure cost estimates for each of the facilities. Table 3-1 presents the results of the estimated closure costs for each facility included in this evaluation. Additional cost details are included in Attachment A.

Table 3-1 Summary of Estimated Closure Costs for Ash Management Infrastructure

	Costs (2014 $)	
Category	**Boswell**	
Units 1,2,4 Fly Ash and SO2 Sludge Pond	$41.62M	
Unit 3 Fly Ash Pond	$29.76M	
Old Unit 3 Bottom Ash Pond	$4.42M	
Units 1-4 Bottom Ash Pond	$1.39M	
Landfill	N/A	
Total	**$77.19M**	

Attachment A

Detailed Cost Estimates

BARR

PREPARED BY: BARR ENGINEERING COMPANY

Minnesota Power
PROJECT: Supplemental Closure Cost Report
LOCATION: Boswell Energy Center
PROJECT: 23/31-1144.02

BY:	SWH	DATE:	3/11/2015
CHECKED BY:	NBN	DATE:	3/12/2015
APPROVED BY:	TJR	DATE:	3/12/2015
ISSUED:	DRAFT	DATE:	
ISSUED:	FINAL	DATE:	3/12/2015

Table A-1 BEC Closure Cost Estimate

Boswell Energy Center

Material Item No.	Item Description	Unit	2014 Cost	Units 1,2,4 Fly Ash and SO2 Sludge Pond Closure		Unit 3 Fly Ash Pond Closure		Old Unit 3 Bottom Ash Pond Closure		Units 1-4 Bottom Ash Pond Closure	
				Total Quantity	Extended Cost	Total Quantity	Extended Cost	Total Quantity	Extended Cost	Total Quantity	Extended Cost
1	FGD Solids Excavation and Relocation	CY	$20	0	$0	590,000	$11,800,000	0	$0	0	$0
2	Fly Ash Excavation and Relocation	CY	$20	490,000	$9,800,000	0	$0	0	$0	0	$0
3	Bottom Ash Excavation and Relocation	CY	$3.50	1,610,000	$5,635,000	960,000	$3,360,000	0	$0	0	$0
4	Geogrid Reinforcing	AC	$11,132	195	$2,171,000	0	$0	0	$0	0	$0
5	General Site Grading	AC	$2,000	292	$584,000	197	$394,000	74	$148,000	55	$110,000
6	Geomembrane Cover - 40mil	AC	$30,492	195	$5,946,000	103	$3,141,000	33	$1,006,000	0	$0
7	Granular Drainage Layer	AC	$32,267	195	$6,292,000	103	$3,323,000	33	$1,065,000	0	$0
8	Rooting Soil Layer	AC	$11,293	292	$3,298,000	197	$2,225,000	74	$836,000	55	$621,000
9	Topsoil Layer	AC	$8,470	292	$2,473,000	197	$1,669,000	74	$627,000	55	$466,000
10	Surface Water Runoff Controls	AC	$5,000	195	$975,000	103	$515,000	33	$165,000	0	$0
11	Turf Establishment	AC	$1,400	292	$409,000	197	$276,000	74	$104,000	55	$77,000
12	Environmental Monitoring System	LS	$100,000	1	$100,000	1	$100,000	1	$100,000	0	$0
13	Stormwater Pond	LS	$500,000	1	$500,000	1	$500,000	0	$0	0	$0
14	Engineering - Facility Final Design	%	4%	-	$1,527,000	-	$1,092,000	-	$162,000	-	$51,000
15	Engineering, CQA and Project Management	%	5%	-	$1,909,000	-	$1,365,000	-	$203,000	-	$64,000
				Total	**$41,620,000**	**Total**	**$29,760,000**	**Total**	**$4,420,000**	**Total**	**$1,390,000**

Note: Extended costs are rounded to nearest $1,000.

BEC Overall Closure Cost Total $77,190,000

BARR

PREPARED BY: BARR ENGINEERING COMPANY

Minnesota Power
PROJECT: Supplemental Closure Cost Report
LOCATION: Boswell Energy Center, Taconite Harbor Energy Center
PROJECT: 23/31-1144.02

BY:	SWH	DATE:	3/11/2015
CHECKED BY:	NBN	DATE:	3/12/2015
APPROVED BY:	TJR	DATE:	3/12/2015
ISSUED:	DRAFT	DATE:	
ISSUED:	FINAL	DATE:	3/12/2015

Table A-3 Construction Materials Cost Data

Material Item No.	Item Description	Unit	Unit Cost	(ft)	Qty / Acre	Cost / Acre	Cost Data Reference
BEC							
1	FGD Solids Excavation and Relocation	CY	$20	N/A	N/A	N/A	Approximated from 2014 Laskin Energy Center Ash Relocation Bids
2	Fly Ash Excavation and Relocation	CY	$20	N/A	N/A	N/A	Approximated from 2014 Laskin Energy Center Ash Relocation Bids
3	Bottom Ash Excavation and Relocation	CY	$3.50	N/A	N/A	N/A	2011 MP Quotes to Move Bottom Ash, Adjusted for Inflation and Reduced for Large Quantity
4	Geogrid Reinforcing	SY	$2.30	N/A	4840	$11,132	Local 2013 Mining Project Bid - Inflated by 20% for 1-Year Inflation and Project Size Reduction
5	General Site Grading	AC	$2,000	N/A	1	$2,000	Placeholder Value for General Site Grading
6	Geomembrane Cover - 40mil	SF	$0.70	N/A	43560	$30,492	Local 2013 Mining Project Bid - Inflated by 20% for 1-Year Inflation and Project Size Reduction
7	Granular Drainage Layer	CY	$20	1	1613	$32,267	Local 2013 Mining Project Bid - Reduced by 20% to account for Local Availability
8	Rooting Soil Layer	CY	$7.00	1	1613	$11,293	Average of Import and Place Topsoil and Embankment Construction
9	Topsoil Layer	CY	$10.50	0.5	807	$8,470	Local 2013 Mining Project Bid - Inflated by 50% for 1-Year Inflation, Project Size Reduction and Unknown Source
10	Surface Water Runoff Controls	AC	$5,000	N/A	1	$5,000	Placeholder Value for Surface Water Runoff Controls
11	Turf Establishment	AC	$1,400	N/A	1	$1,400	Local 2013 Mining Project Bid - Inflated by 20% for 1-Year Inflation and Project Size Reduction
12	Environmental Monitoring System	LS	$100,000	N/A	N/A	N/A	Placeholder for Installation/Redevelopment/Repair of Some Wells
13	Stormwater Pond	LS	$500,000	N/A	N/A	N/A	
14	Engineering - Facility Final Design	%	4%	N/A	N/A	N/A	Percentage of Total Construction Costs
15	Engineering, CQA and Project Management	%	5%	N/A	N/A	N/A	Percentage of Total Construction Costs

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OAG No. 1148

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota		**MPUC Docket No.**	E015/GR-16-664
By:	Ryan Barlow	**Date of Request:**	March 6, 2017
Telephone:	(651) 757-1432	**Due Date:**	March 16, 2017

For all responses show amounts for Total Company and the Minnesota retail jurisdiction unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Minke at 18, Schedule 10

In Schedule 10, Burns McDonnell states, "[W]e see no technical reasons that Boswell Energy Center could not physically be operated until 2050, *with appropriate maintenance and investments into replacements and upgrades*."

Produce all estimates, analysis, and documents regarding the future "maintenance and investments into replacements and upgrades" that would be necessary to operate any BEC units beyond the end of their current remaining life, or to 2050.

RESPONSE:

To clarify, as described in pages 14-24 of Company witness Herbert G. Minke's Direct Testimony, Minnesota Power is requesting in this proceeding that the life of all BEC Units – Boswell Units 1&2, Unit 3, Unit 4, and the Boswell Common Facilities-be consolidated into one remaining life and be extended until 2050. This request relates to establishing the remaining useful life for cost recovery purposes, and is not meant to change the operational life or lives of BEC.

One of the reasons for extending the useful life of BEC to 2050 as noted on page 18 of Mr. Minke's Direct Testimony is the fact that the BEC4 and BEC3 retrofits justify extending the life for the length of time the equipment may operate. As noted above, Burns & McDonald analyzed

Witness:	Joshua J. Skelton
Response by:	Joshua J. Skelton
Title:	Vice President - MP Generation
Department:	Generation Operations
Telephone:	218-313-4694

each BEC unit and determined that with proper maintenance and investments, that BEC could be operated until 2050.

While Minnesota Power has not conducted an estimate of the costs estimates, analysis, and documents regarding the future “maintenance and investments into replacements and upgrades” that would be necessary to operate any BEC units beyond the end of their current remaining life, or to 2050, Minnesota Power’s 2017 test year capital budget for BEC includes routine maintenance investments that are designed to enable continued reliable operation of these assets. These investments are described on pages 17-20 and Schedule 1 of the Direct Testimony of Company witness Joshua J. Skelton.

In addition to the investments planned for 2017, Minnesota Power plans for long term capital and maintenance projects for its generation units as part of its long term planning and Integrated Resource Plan evaluations using a 15 year planning horizon. These plans outline the asset strategy and major equipment cycle repairs that are anticipated over the 15 year planning horizon.

A major driver in the maintenance and capital spend for BEC3 and BEC 4 over the next 15 years will be ongoing maintenance and repair of the boilers and turbine-generators for each unit. For the boilers, Minnesota Power plans for scheduled maintenance of these boilers every 18 months an alternating cycle such that only one boiler will be undergoing maintenance at the one time. Boiler maintenance includes inspection of the boiler and then repairing and replacing worn parts, boiler tubes, and burners to assure the function and reliability of the assets. For the turbines, Minnesota Power inspects each turbine on a five year cycle makes necessary valve repairs at that time. In addition, every ten years, Minnesota Power inspects the turbines for major repairs and potential replacement. For both the boilers and the turbines, the costs of these maintenance activities depends on extent of the repairs and replacement performed during each maintenance cycle. In addition to these planned maintenance activities, there may be additional investments that are needed due to unforeseen circumstances. While the current planning horizon is currently forecasting the known maintenance needs of the BEC assets to 2034, it is reasonable that similar duty cycle maintenance will continue to enable the facility to be operational to 2050.

Witness:	Joshua J. Skelton
Response by:	Joshua J. Skelton
Title:	Vice President - MP Generation
Department:	Generation Operations
Telephone:	218-313-4694

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

OAG No. 1155

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota	**MPUC Docket No.**	E015/GR-16-664
By: Ryan Barlow	**Date of Request:**	March 29, 2017
Telephone: (651) 757-1473	**Due Date:**	April 10, 2017

For all responses show amounts for Total Company and the Minnesota retail jurisdiction unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: OAG IR 1148

OAG IR 1148 requests "all estimates, analysis, and documents regarding future 'maintenance and investments into replacements and upgrades'" at the BEC facilities. MP provided a narrative response that did not include any documentation or analysis.

Produce all internal documents and analysis regarding potential future maintenance, including any sensitivity analysis involving that "depends on the extent of the repairs and replacement performed during each maintenance cycle," or confirm that MP possesses no documents and has conducted no analysis regarding the future maintenance and investments costs related to replacements or upgrades for the BEC investments.

RESPONSE:

To clarify, as described in pages 14-24 of Company witness Herbert G. Minke's Direct Testimony, Minnesota Power is requesting in this proceeding that the life of all BEC Units – Boswell Units 1&2, Unit 3, Unit 4, and the Boswell Common Facilities-be consolidated into one remaining life and be extended until 2050. This request relates to establishing the remaining useful life for cost recovery purposes, and is not meant to change the operational life or lives of BEC.

Given that Minnesota Power has not proposed to change the operational life or lives of BEC, Minnesota Power has not prepared a detailed cost estimate of the future "maintenance and

Witness: Joshua J. Skelton
Response by: Joshua J. Skelton
Title: Vice President - MP Generation
Department: Generation Operations
Telephone: 218-313-4694

investments into replacements and upgrades" that would be necessary to operate any BEC units beyond the end of their current remaining life, or to 2050.

However, as noted in the Company's response to OAG IR 1148, one of the reasons for extending the life of BEC to 2050 is the fact that BEC 3 and BEC 4 have recently undergone substantial environmental and efficiency improvements that justify extending the life for the length of time this equipment may operate. Specifically, this includes an environmental retrofit that was substantially completed at BEC 4 in 2016 and a major environmental upgrade at BEC 3 that was completed in 2009. These improvements are described on pages 13-18 of the Direct Testimony of Company witness Joshua Skelton. In addition, as noted in the Direct Testimony of Company witness Joshua Skelton, Minnesota Power plans to retire BEC 1&2 at the end of 2018.

Given these extensive improvements at BEC 3 and BEC 4 and barring any new environmental regulations, Minnesota Power does not anticipate that substantial improvements will be needed at these units to operate these facilities until 2050. Rather, Minnesota Power anticipates that the capital and O&M investments necessary to operate these units until 2050 will be routine maintenance-type investments such as replacing worn or damaged components to maintain the efficiency and reliability of these units. These investments and repairs for BEC 3 and 4 typically are coupled with the outage cycles and maintenance strategy of the units. This includes having an 18 month cycle for boiler and burner repairs, 5 year cycle for turbine valves and control work, and 10 year cycles for turbine-generator inspection and repairs. The capital projects that Minnesota Power will undertake in 2017 for BEC 3 and BEC 4, as described on pages 18-19 of Mr. Skelton's Direct Testimony, are examples of the types of capital investments that will be required to maintain these assets until 2050.

In addition, as part of Minnesota Power's Integrated Resource Plan ("IRP"), Minnesota Power analyzed various short-term and long-term plans for its generation units. Minnesota Power's most recent IRP examined the both a short-term plan (2015-2019) and a long-term plan (2019-2029). As part of this analysis, Minnesota Power developed high-level cost estimates for both capital and O&M expenses associated with each of these scenarios that were studied.

To develop the capital cost estimates for the IRP analysis, Minnesota Power examined current inspection reports, monitoring reports, repair reports, and operating data for BEC to estimate the capital investments that may be needed through the study period. The projected costs for these capital projects were estimated by relying on past experience with completed projects of a similar scope and then adjusting these costs for inflation. Minnesota Power also relied on vendor estimates to develop certain cost estimates. OAG 1155.01 Attach TS provides examples of the types of inspection reports and vendor estimates used by Minnesota Power to develop these cost estimates. Given the voluminous nature of these reports, Minnesota Power is providing only examples of the types of reports relied on by Minnesota Power. It is important to note that the future capital and O&M costs analyzed as part of the most recent IRP are subject to change

Witness: Joshua J. Skelton
Response by: Joshua J. Skelton
Title: Vice President - MP Generation
Department: Generation Operations
Telephone: 218-313-4694

based on the reliability and performance of the BEC assets, known problems or failures, changes in environmental regulations and many other factors.

The information assigned a trade secret designation herein includes project-specific information and has been marked as trade secret as defined by Minn. Stat. § 13.37, subd. 1(b). The information derives an independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from their use.

Witness: Joshua J. Skelton
Response by: Joshua J. Skelton
Title: Vice President - MP Generation
Department: Generation Operations
Telephone: 218-313-4694

OAG IR 1155.01 Attach PUB is Trade Secret in its entirety

OAG No. 1156

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota	**MPUC Docket No.**	E015/GR-16-664
By: Ryan Barlow	**Date of Request:**	March 29, 2017
Telephone: (651) 757-1473	**Due Date:**	April 10, 2017

For all responses show amounts for Total Company and the Minnesota retail jurisdiction unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: OAG IR 1148

MP states that future investments required at BEC 3 and 4 may include maintenance and/or replacement of boilers and turbines. Provide the following information:

1. The expected lifespan of the boilers and turbines currently installed in BEC 3 and 4;
2. The historical lifespan of similar boilers and turbines in other facilities nationwide;
3. Any manufacturer representations regarding the lifespan of the boilers or turbines;
4. An estimate of the cost replacing the boilers and turbines at BEC 3 or BEC 4, including the cost of comparable replacements at similar facilities if available.

RESPONSE:

It is important to be clear that the Company's response to OAG 1148 states that future investments required at BEC 3 and 4 "may include" the maintenance and/or replacement of boilers and turbines. Whether maintenance and/or replacement of boilers and turbines are required will depend on the condition of this equipment.

With this clarification, please find the responses to the numbered questions below:

Witness:	Joshua J. Skelton
Response by:	Joshua J. Skelton
Title:	Vice President-Generation Operations
Department:	Generation Operations
Telephone:	218-313-4694

1. For purposes of this response, Minnesota Power assumes that this question refers to the physical life of these assets. Minnesota Power does not have an estimated physical lifespan for the whole boiler or turbine as the physical life of these assets depends on the individual operating conditions and maintenance of these assets. It is Minnesota Power's practice to inspect and replace worn or damaged components during regular maintenance intervals or on an as-needed basis if components are damaged between maintenance cycles.

The current maintenance practices for BEC 3 and 4 include regular outage intervals to allow for inspections, replacement of worn parts, repairs, or modifications to existing systems. These intervals can vary depending on energy market conditions, other planned work, or accelerated due to a failure of a component or system. In general, the interval for boiler tube and burner inspection repairs occurs every 18 months, turbine valves and control systems every five years, and steam turbine and generator inspections every 10 years. These intervals follow original equipment manufacturer ("OEM") recommendations, insurance carrier recommendations, and comply with all state and federal boiler code as well as Minnesota Power's maintenance practices to preserve the reliability of the equipment and units.

2. As each unit and facility can be unique in mission and design, Minnesota Power is not aware of any database for this type of information.

3. Minnesota Power is not aware of any estimates, guarantees, or warranties by the manufacturers for the lifespan of these assets. The operating life for these assets will depend on how they are operated and maintained.

4. There are no known cost estimates for replacing the boilers or turbines at similar facilities. Also as clarified above, the plans for BEC 3 and BEC 4 include making repairs and maintaining the assets to serve their current mission in future years as outlined in our most recent Integrated Resource Plan ("IRP").

Given the nature and condition of the equipment can change between outage intervals, the outage cycles described in subpart (1) are used to place hold time frames when major work can be executed on the boilers and turbines of BEC 3 and BEC 4. As the planned horizons approach, known equipment monitoring and recent inspection are utilized to finalize the scope of necessary repairs and maintenance. The estimated cost for this maintenance and repair are typically based on past experiences, known equipment conditions, and engineering estimates similar to those outlined in the Company's response to OAG IR 1155.

The next planned major maintenance cycles of this nature are currently being planned for BEC3 in 2019 and for BEC4 in 2020. The capital estimates for the general categories of boiler and turbine-generator repairs and worn part replacements are summarized in OAG IR 1156.01 Attach.

Witness: Joshua J. Skelton
Response by: Joshua J. Skelton
Title: Vice President-Generation Operations
Department: Generation Operations
Telephone: 218-313-4694

Unit	Year	Total Estimated Dollars in $1,000's	General Category	Project Description
BEC3	2018	$500	Boiler	COUTANT BOTTOM OF THE BOILER - Material Order
BEC3	2018	$1,000	Turbine	TURBINE OVERHAUL - Material Order
BEC3	2019	$1,500	Boiler	COUTANT BOTTOM OF THE BOILER REPLACEMENT LABOR/MATERIALS
BEC3	2019	$100	Boiler	LPA SCREENS - Last Pass Ash Screen replacements
BEC3	2019	$55	Boiler	BEC3 Main Steam Spring Can Replacement
BEC3	2019	$4,000	Turbine	TURBINE OVERHAUL- HP LP valves, LP Blading collector rings (Inpsect and Repair)
BEC4	2019	$250	Boiler	SH (Super Heater) Platen Pendent Repalcement - Material Order
BEC4	2020	$3,000	Turbine	TURBINE / GENERATOR / VALVES (Inpect and Repair)
BEC4	2020	$3,000	Boiler	BOILER REPAIRS (Inspect, Labor and Materials)
BEC4	2020	$4,750	Boiler	REPLACE SUPERHEAT PLATENT PENDANT
BEC4	2020	$1,500	Generator	GENERATOR REWIND (INSPECT AND REPAIR)
BEC4	2020	$3,000	Boiler	REPLACE RH (REHEAT) OUTLET HEADER

OAG No. 1157

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota		**MPUC Docket No.**	E015/GR-16-664
By:	Ryan Barlow	**Date of Request:**	March 29, 2017
Telephone:	(651) 757-1473	**Due Date:**	April 10, 2017

<u>For all responses show amounts for Total Company and the Minnesota retail jurisdiction unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.</u>

Reference OAG IR 1148

Produce the expected O&M cost for the BEC investments from 2016 to 2050, assuming that the Commission approves MP's request to extend the depreciation rates until 2050. Produce all documents and analysis that MP relied upon for its estimates

RESPONSE:

To clarify, as described in pages 14-24 of Company witness Herbert G. Minke's Direct Testimony, Minnesota Power is requesting in this proceeding that the life of all BEC Units – Boswell Units 1&2, Unit 3, Unit 4, and the Boswell Common Facilities-be consolidated into one remaining life and be extended until 2050. This request relates to establishing the remaining useful life for cost recovery purposes, and is not meant to change the operational life or lives of BEC.

Given that Minnesota Power has not proposed to change the operational life or lives of BEC, Minnesota Power has not prepared a detailed cost estimate of the future "maintenance and investments into replacements and upgrades" that would be necessary to operate any BEC units beyond the end of their current remaining life, or to 2050. However, Minnesota Power's 2017 test year O&M budget for BEC includes required staffing, environmental compliance and other O&M costs required for reliable operation of these assets in 2017. These O&M costs are described on pages 45-49 of the Direct Testimony of Company witness Joshua J. Skelton. As noted in the Direct Testimony of Mr. Skelton, the Company has announced plans to retire

Witness: Joshua J. Skelton
Response by: Joshua J. Skelton
Title: Vice President - MP Generation
Department: Generation Operations
Telephone: 218-313-4694

Boswell Units 1 and 2 (BEC 1&2) at the end of 2018. Currently all site costs relative to operating and maintaining the remaining assets and common systems following the retirement of BEC 1&2 is being reviewed and developed. At this time, Minnesota Power anticipates that the the O&M costs for the common assets serving BEC, following the retirement of these units (BEC 1&2), will be in line with the current 2017 O&M costs.

In addition, as part of Minnesota Power's Integrated Resource Plan ("IRP"), Minnesota Power analyzed various short-term and long-term plans for its generation units. Minnesota Power's most recent IRP examined the both a short-term plan (2015-2019) and a long-term plan (2019-2029). As part of this analysis, Minnesota Power developed high-level cost estimates for both capital and O&M expenses associated with each of these scenarios that were studied. While these estimates have been performed for the facility at a high-level, the plans and forecasts are still undergoing further development to understand the allocation of costs to the remaining units following the retirement of BEC 1&2 at the end of 2018.

Witness: Joshua J. Skelton
Response by: Joshua J. Skelton
Title: Vice President - MP Generation
Department: Generation Operations
Telephone: 218-313-4694

OAG No. 1154

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota		**MPUC Docket No.**	E015/GR-16-664
By:	Ryan Barlow	**Date of Request:**	March 29, 2017
Telephone:	(651) 757-1473	**Due Date:**	April 10, 2017

For all responses show amounts for Total Company and the Minnesota retail jurisdiction unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Using the rate of return requested by MP in this proceeding, calculate the total returns on rate base earned from the BEC investments under two scenarios: 1) using the currently approved depreciation rate establishing an end of remaining life of 2024 for BEC 1 and 2, 2034 for BEC 3, 2035 for BEC 4, and 2030 for the common facilities; and 2) extending the depreciation of all BEC assets to 2050 as requested by MP.

For each scenario, also provide the amount of depreciation expense and remaining plant balance for each year. For each year of depreciation expense, separately break out the depreciation, removal expense, and salvage value.

Provide your answer in Excel format with all links and formulas intact.

RESPONSE:

1) Refer to OAG IR 1154.01 Attach for the requested information. MP's total return on rate base using the currently approved end of remaining lives for BEC assets is $70,487,969 on a Total Company basis ($59,573,369 MN Jurisdictional) is shown in the "Current Lives" tab, line 54.
2) Extending the remaining lives for all BEC assets to 2050 yields a total return on rate base of $71,450,513 on a Total Company basis ($60,385,218 MN Jurisdictional as shown in the "Extended Lives" tab, line 54.

Witness:	Herbert G. Minke, III
Response by:	Mike Donahue
Title:	Cost & Pricing Analyst II
Department:	Rates
Telephone:	218-355-3408

As shown in the "Current Lives" tab, line 71, with the currently approved remaining lives, the test year depreciation expense is $55,044,558 on a Total Company basis ($46,426,836 MN Jurisdictional). As shown in the "Extended Lives" tab, line 71, extending the remaining lives to 2050 for all BEC assets decreases the test year depreciation expense to $26,467,953 on a Total Company basis ($22,324,156 MN Jurisdictional). See OAG IR 1154.02 Attach for the requested details of depreciation expense and remaining plant balance for each year.

Witness:	Herbert G. Minke, III
Response by:	Mike Donahue
Title:	Cost & Pricing Analyst II
Department:	Rates
Telephone:	218-355-3408

Estimate of Boswell Revenue Requirements by Unit

= Updated for Supplemental Filing

= removed Boswell life ext. impact

		TOTAL COMPANY							MN JURISDICTIONAL				
	BEC 1	BEC 2	BEC 3	BEC 4	Common			BEC 1	BEC 2	BEC 3	BEC 4	Common
A Book Basis of Property - Plant												
1 12/31/16 Plant In-Service	46,433,623	41,661,605	472,373,279	607,800,372	205,914,234							
2 12/31/17 Plant In-Service	47 630 790	42 850 295	477 054 022	613 432 392	212 721 433							
3 Average Test Year Plant In-Service (prior to Contra and Adjustments)	47,032,207	42,255,950	474,713,651	610,616,382	209,317,834	DPROD	0 843600	39,676,369	35,647,119	400,468,436	515,115,980	176,580,524
4 Less Average FERC Contra	-	-	-	(4,148,162)	(23,271)	DPRODR	0 000000	-	-	-	-	-
5 Less Average Retail Contra	-	-	-	(18,918,971)	(106,134)	DPRODJ	1.000000	-	-	-	(18,918,971)	(106,134)
6 Less Average ARO Asset	(1,066,080)	(1,091,000)	(14,496,128)	(5,520,712)	(6,271,167)	DPROD	0 843600	(899,345)	(920,368)	(12,228,934)	(4,657,273)	(5,290,356)
7 Less Average Adj. for Boswell 3 Env. Project Limit	-	-	(15,231,418)	-	-	DPROD	0.843600	-	-	(12,849,224)	-	-
8 Average Test Year Plant (Net of Contra w/ Adjustments)	45,966,127	41,164,950	444,986,105	582,028,537	202,917,262			38,777,024	34,726,752	375,390,278	491,539,736	171,184,034
B Book Basis of Property - Depreciation												
9 Total Accumulated Depreciation 12/31/16	27,829,114	25,398,783	155,590,741	169,303,900	112,275,100							
10 Plus: 2017 Depreciation	2,888,562	2,556,264	18,200,790	24,961,282	7,720,707							
11 Less: Retirements	(391,522)	-	(663,425)	(1,783,658)	(417,895)							
12 Less: Cost of Removal & Salvage & Other Credits	(100,000)	-	(57,319)	(500,000)	(92,094)							
13 Less: Decommissioning Adj.	(718,439)	(731,228)	(1,455,756)	(1,887,888)	(389,573)							
14 Less: COR/ARO Reclass	-	-	-	-	-							
15 Total Accumulated Depreciation 12/31/17 (Prior to Adj)	29,507,715	27,223,819	171,615,031	190,093,636	119,096,245							
16 Average Test Year Depreciation (Prior to Adj.)	28,668,415	26,311,301	163,602,886	179,698,768	115,685,673	DSTMPLT	0 843441	24,180,116	22,192,029	137,989,378	151,565,305	97,574,037
17 Less: Average FERC Contra AFUDC Accum. Depreciation	-	-	-	(318,089)	(1,416)	DPRODR	0 000000	-	-	-	-	-
18 Less: Average Retail Contra AFUDC Accum. Depreciation	-	-	-	(1,450,743)	(6,460)	DPRODJ	1 000000	-	-	-	(1,450,743)	(6,460)
19 Less: Average ARO Accumulated Depreciation	(266,415)	(280,687)	(7,029,065)	(1,951,725)	(2,365,620)	DSTMPLT	0 843441	(224,705)	(236,743)	(5,928,601)	(1,646,165)	(1,995,261)
20 Less: Average Boswell 3 Env. Project Limit	-	-	(4,652,958)	-	-	DSTMPLT	0 843441	-	-	(3,924,495)	-	-
21 Less: Average Boswell Life Extension Impact	-	-	-	-	-	DSTMPLT	0 843441	-	-	-	-	-
22 Plus: Average Decommissioning	1,863,039	1,848,373	10,039,677	10,081,008	2,882,899	DSTMPLT	0.843441	1,571,363	1,558,994	8,467,875	8,502,735	2,431,555
23 Average Test Year Accumulated Depreciation (w/ Adj.)	30,265,039	27,878,987	161,960,540	186,059,219	116,195,076			25,526,774	23,514,280	136,604,156	156,971,132	98,003,871
C Book Basis of Property - Summary												
24 Average Test Year Plant (Net of Contra w/ Adjustments)	45,966,127	41,164,950	444,986,105	582,028,537	202,917,262			38,777,024	34,726,752	375,390,278	491,539,736	171,184,034
25 Less: Average Test Year Acc. Depreciation (w/ Adj.)	(30,265,039)	(27,878,987)	(161,960,540)	(186,059,219)	(116,195,076)			(25,526,774)	(23,514,280)	(136,604,156)	(156,971,132)	(98,003,871)
26 Average Test Year Net Plant (w/ Adjustments)	15,701,088	13,285,963	283,025,565	395,969,318	86,722,186			13,250,251	11,212,472	238,786,122	334,568,604	73,180,163
D Tax Basis of Property												
27 Average Test Year Plant (Net of Contra w/ Adjustments)	45,966,127	41,164,950	444,986,105	582,028,537	202,917,262							
28 Average Test Year Accumulated Tax Depreciation	(40 691 103)	(32 641 376)	(400 900 439)	(469 984 666)	(168 865 922)							
29 Average Test Year Tax Basis	5,275,023	8,523,574	44,085,665	112,043,871	34,051,340							
30 Average Test Year Tax Book Difference	10,426,065	4,762,389	238,939,899	283,925,447	52,670,846							
31 Income Tax Rate 1/	41.37%	41 37%	41.37%	41.37%	41.37%							
32 Average Test Year Acc. Deferred Income Tax Liability	4,313,263	1,970,200	98,849,436	117,459,957	21,789,929							

Estimate of Boswell Revenue Requirements by Unit

= Updated for Supplemental Filing

= removed Boswell life ext. impact

		TOTAL COMPANY							MN JURISDICTIONAL					
		BEC 1	BEC 2	BEC 3	BEC 4	Common			BEC 1	BEC 2	BEC 3	BEC 4	Common	
E	**Revenue Requirements - Return on Rate Base**													
33	Average Test Year Net Plant	15,701,088	13,285,963	283,025,565	395,969,318	86,722,186	Various 2/		13,250,251	11,212,472	238,786,122	334,568,604	73,180,163	
34	Less: Average ADITL - Def Taxes	(4,313,263)	(1,970,200)	(98,849,436)	(117,459,957)	(21,789,929)	DSTMPLT	0 843441	(3,637,983)	(1,661,748)	(83,373,665)	(99,070,541)	(18,378,519)	
35	Plus: Cash Working Capital	4 193 802	4 196 914	24 537 606	30 220 189	2 470	Various 3/		3 560 754	3 563 190	20 826 967	25 651 943	2 141	
36	Average Test Year Rate Base	15,581,627	15,512,677	208,713,734	308,729,549	64,934,727			13,173,022	13,113,914	176,239,423	261,150,006	54,803,785	
37	Rate of Return 4/	0.1149	0.1149	0.1149	0.1149	0.1149	**Tot. Company**		0.1149	0.1149	0.1149	0.1149	0.1149	**MN Jurisdiction**
38	Return on Test Year Average Rate Base	1,790,329	1,782,407	23,981,208	35,473,025	7,461,000	**70,487,969**		1,513,580	1,506,789	20,249,910	30,006,136	6,296,955	**59,573,369**
F	**Revenue Requirements - O&M/Expenses**													
39	O&M Steam Production (Demand) 5/	1,826,228	1,681,157	7,669,686	10,053,880	-	DPROD	0 843600	1,540,606	1,418,224	6,470,147	8,481,453	-	
40	O&M Steam Production (Energy) 5/	1,987,938	1,813,986	6,714,416	7,265,780	-	EPROD	0 843070	1,675,971	1,529,317	5,660,723	6,125,561	-	
41	Fuel O&M 5/	10,049,634	10,059,209	50,039,758	61,572,815	11,739	EPROD	0 843070	8,472,545	8,480,617	42,187,019	51,910,193	9,897	
42	Other Power Supply Production Demand	77,952	78,067	418,629	548,317	-	DPROD	0 843600	65,760	65,857	353,155	462,560	-	
43	Property Insurance 6/	23,619	19,986	425,761	595,664	130,458	PLANT	0 857630	20,257	17,141	365,145	510,860	111,885	
44	Regulatory Expenses	18,219	18,246	97,844	128,155	-	PLANT	0 857630	15,625	15,648	83,914	109,910	-	
45	General Plant	82,882	83,005	445,110	583,002	-	LABLAG	0 870129	72,118	72,225	387,303	507,287	-	
46	Other A&G	809,293	810,492	4,346,203	5,692,626	-	LABLAG	0 870129	704,190	705,233	3,781,759	4,953,322	-	
47	Total Test Year O & M Expense	14,875,766	14,564,148	70,157,406	86,440,239	142,197			12,567,072	12,304,263	59,289,165	73,061,145	121,781	
48	Emissions Fees 5/	196,900	187,058	118,297	269,011	-	EPROD	0 843070	166,000	157,703	99,733	226,795	-	
49	Test Year Depreciation Expense (Incl. all Adj. and Contra)	3,007,762	2,677,229	17,589,076	24,077,316	7,693,175	DSTMPLT	0 843441	2,536,870	2,258,085	14,835,347	20,307,795	6,488,739	
							Tot. Company Depr. Exp. 55,044,558							**MN Jurisdiction Depr. Exp. 46,426,836**
50	Property Tax 5/	654,160	663,923	3,534,410	4,569,348	-	PROPTAX	0 865899	566,436	574,890	3,060,441	3,956,592	-	
51	Payroll Taxes 5/	135,446	131,223	503,786	522,783	11,739	LABOR	0 870129	117,856	114,181	438,359	454,889	10,214	
G	**Total Revenue Requirements**													
52	Annual Revenue Requirements	20,660,363	20,005,987	115,884,182	151,351,722	15,308,111			17,467,814	16,915,910	97,972,954	128,013,352	12,917,690	

Notes: 1/ Minnesota Composite Income Tax Rate
2/ Because Boswell 4 and Common have Contra AFUDC, cannot use only DPROD to allocate Avg. Test Year Net Plant, refer to Sections A, B, C allocated above.
3/ Individual components of cash working capital allocated as shown in the Cash Working Capital-Detail tab.
4/ Minnesota Power's proposed pre-tax rate of return of 11.49%
5/ Per MP's 2017 Test Year Budget.
6/ Total Boswell amount allocated among units and common based on net plant in service (Line 26)

Estimate of Boswell Revenue Requirements by Unit

= Updated for Supplemental Filing

		TOTAL COMPANY							MN JURISDICTIONAL				
		BEC 1	BEC 2	BEC 3	BEC 4	Common			BEC 1	BEC 2	BEC 3	BEC 4	Common
A	**Book Basis of Property - Plant**												
	1 12/31/16 Plant In-Service	46,433,623	41,661,605	472,373,279	607,800,372	205,914,234							
	2 12/31/17 Plant In-Service	47,630,790	42,850,295	477,054,022	613,432,392	212,721,433							
	3 Average Test Year Plant In-Service (prior to Contra and Adjustments)	47,032,207	42,255,950	474,713,651	610,616,382	209,317,834	DPROD	0 843600	39,676,369	35,647,119	400,468,436	515,115,980	176,580,524
	4 Less Average FERC Contra	-	-	-	(4,148,162)	(23,271)	DPRODR	0 000000	-	-	-	-	-
	5 Less Average Retail Contra	-	-	-	(18,918,971)	(106,134)	DPRODJ	1 000000	-	-	-	(18,918,971)	(106,134)
	6 Less Average ARO Asset	(1,066,080)	(1,091,000)	(14,496,128)	(5,520,712)	(6,271,167)	DPROD	0 843600	(899,345)	(920,368)	(12,228,934)	(4,657,273)	(5,290,356)
	7 Less Average Adj. for Boswell 3 Env. Project Limit	-	-	(15,231,418)	-	-	DPROD	0 843600	-	-	(12,849,224)	-	-
	8 Average Test Year Plant (Net of Contra w/ Adjustments)	45,966,127	41,164,950	444,986,105	582,028,537	202,917,262			38,777,024	34,726,752	375,390,278	491,539,736	171,184,034
B	**Book Basis of Property - Depreciation**												
	9 Total Accumulated Depreciation 12/31/16	27,829,114	25,398,783	155,590,741	169,303,900	112,275,100							
	10 Plus: 2017 Depreciation	2,888,562	2,556,264	18,200,790	24,961,282	7,720,707							
	11 Less: Retirements	(391,522)	-	(663,425)	(1,783,658)	(417,895)							
	12 Less: Cost of Removal & Salvage & Other Credits	(100,000)	-	(57,319)	(500,000)	(92,094)							
	13 Less: Decommissioning Adj.	(718,439)	(731,228)	(1,455,756)	(1,887,888)	(389,573)							
	14 Less: COR/ARO Reclass	-	-	-	-	-							
	15 Total Accumulated Depreciation 12/31/17 (Prior to Adj)	29,507,715	27,223,819	171,615,031	190,093,636	119,096,245							
	16 Average Test Year Depreciation (Prior to Adj.)	28,668,415	26,311,301	163,602,886	179,698,768	115,685,673	DSTMPLT	0 843441	24,180,116	22,192,029	137,989,378	151,565,305	97,574,037
	17 Less: Average FERC Contra AFUDC Accum. Depreciation	-	-	-	(318,089)	(1,416)	DPRODR	0 000000	-	-	-	-	-
	18 Less: Average Retail Contra AFUDC Accum. Depreciation	-	-	-	(1,450,743)	(6,460)	DPRODJ	1 000000	-	-	-	(1,450,743)	(6,460)
	19 Less: Average ARO Accumulated Depreciation	(266,415)	(280,687)	(7,029,065)	(1,951,725)	(2,365,620)	DSTMPLT	0 843441	(224,705)	(236,743)	(5,928,601)	(1,646,165)	(1,995,261)
	20 Less: Average Boswell 3 Env. Project Limit	-	-	(4,652,958)	-	-	DSTMPLT	0 843441	-	-	(3,924,495)	-	-
	21 Less: Average Boswell Life Extension Impact	(1,125,234)	(1,024,499)	(4,261,686)	(5,512,805)	(2,364,079)	DSTMPLT	0 843441	(949,068)	(864,104)	(3,594,481)	(4,649,726)	(1,993,961)
	22 Plus: Average Decommissioning	1,863,039	1,848,373	10,039,677	10,081,008	2,882,899	DSTMPLT	0 843441	1,571,363	1,558,994	8,467,875	8,502,735	2,431,555
	23 Average Test Year Accumulated Depreciation (w/ Adj.)	29,139,805	26,854,488	157,698,854	180,546,414	113,830,997			24,577,705	22,650,176	133,009,676	152,321,406	96,009,910
C	**Book Basis of Property - Summary**												
	24 Average Test Year Plant (Net of Contra w/ Adjustments)	45,966,127	41,164,950	444,986,105	582,028,537	202,917,262			38,777,024	34,726,752	375,390,278	491,539,736	171,184,034
	25 Less: Average Test Year Acc. Depreciation (w/ Adj.)	(29,139,805)	(26,854,488)	(157,698,854)	(180,546,414)	(113,830,997)			(24,577,705)	(22,650,176)	(133,009,676)	(152,321,406)	(96,009,910)
	26 Average Test Year Net Plant (w/ Adjustments)	16,826,322	14,310,462	287,287,251	401,482,123	89,086,265			14,199,319	12,076,576	242,380,602	339,218,330	75,174,124
D	**Tax Basis of Property**												
	27 Average Test Year Plant (Net of Contra w/ Adjustments)	45,966,127	41,164,950	444,986,105	582,028,537	202,917,262							
	28 Average Test Year Accumulated Tax Depreciation	(40 691 103)	(32 641 376)	(400 900 439)	(469 984 666)	(168 865 922)							
	29 Average Test Year Tax Basis	5,275,023	8,523,574	44,085,665	112,043,871	34,051,340							
	30 Average Test Year Tax Book Difference	11,551,299	5,786,888	243,201,585	289,438,252	55,034,925							
	31 Income Tax Rate 1/	41 37%	41.37%	41.37%	41.37%	41 37%							
	32 Average Test Year Acc. Deferred Income Tax Liability	4,778,772	2,394,035	100,612,496	119,740,605	22,767,949							

Estimate of Boswell Revenue Requirements by Unit

= Updated for Supplemental Filing

		TOTAL COMPANY							MN JURISDICTIONAL					
		BEC 1	BEC 2	BEC 3	BEC 4	Common			BEC 1	BEC 2	BEC 3	BEC 4	Common	
E	**Revenue Requirements - Return on Rate Base**													
33	Average Test Year Net Plant	16,826,322	14,310,462	287,287,251	401,482,123	89,086,265	Various 2/		14,199,319	12,076,576	242,380,602	339,218,330	75,174,124	
34	Less: Average ADITL - Def Taxes	(4,778,772)	(2,394,035)	(100,612,496)	(119,740,605)	(22,767,949)	DSTMPLT	0 843441	(4,030,612)	(2,019,228)	(84,860,702)	(100,994,133)	(19,203,421)	
35	Plus: Cash Working Capital	4,193,802	4,196,914	24,537,606	30,220,189	2,470	Various 3/		3,560,754	3,563,190	20,826,967	25,651,943	2,141	
36	Average Test Year Rate Base	16,241,352	16,113,341	211,212,361	311,961,707	66,320,787			13,729,460	13,620,539	178,346,867	263,876,140	55,972,844	
37	Rate of Return 4/	0.1149	0.1149	0.1149	0.1149	0.1149	**Tot. Company**		0.1149	0.1149	0.1149	0.1149	0.1149	**MN Jurisdiction**
38	Return on Test Year Average Rate Base	1,866,131	1,851,423	24,268,300	35,844,400	7,620,258	**71,450,513**		1,577,515	1,565,000	20,492,055	30,319,368	6,431,280	**60,385,218**
F	**Revenue Requirements - O&M/Expenses**													
39	O&M Steam Production (Demand) 5/	1,826,228	1,681,157	7,669,686	10,053,880	-	DPROD	0 843600	1,540,606	1,418,224	6,470,147	8,481,453	-	
40	O&M Steam Production (Energy) 5/	1,987,938	1,813,986	6,714,416	7,265,780	-	EPROD	0 843070	1,675,971	1,529,317	5,660,723	6,125,561	-	
41	Fuel O&M 5/	10,049,634	10,059,209	50,039,758	61,572,815	11,739	EPROD	0 843070	8,472,545	8,480,617	42,187,019	51,910,193	9,897	
42	Other Power Supply Production Demand	77,952	78,067	418,629	548,317	-	DPROD	0 843600	65,760	65,857	353,155	462,560	-	
43	Property Insurance 6/	24,865	21,147	424,539	593,290	131,647	PLANT	0 857630	21,325	18,137	364,097	508,824	112,905	
44	Regulatory Expenses	18,219	18,246	97,844	128,155	-	PLANT	0 857630	15,625	15,648	83,914	109,910	-	
45	General Plant	82,882	83,005	445,110	583,002	-	LABLAG	0 870129	72,118	72,225	387,303	507,287	-	
46	Other A&G	809,293	810,492	4,346,203	5,692,626	-	LABLAG	0 870129	704,190	705,233	3,781,759	4,953,322	-	
47	Total Test Year O & M Expense	14,877,011	14,565,309	70,156,184	86,437,865	143,386			12,568,140	12,305,259	59,288,116	73,059,109	122,801	
48	Emissions Fees 5/	196,900	187,058	118,297	269,011	-	EPROD	0 843070	166,000	157,703	99,733	226,795	-	
49	Test Year Depreciation Expense (Incl. all Adj. and Contra)	757,294	628,231	9,065,704	13,051,707	2,965,017	DSTMPLT	0 843441	638,733	529,876	7,646,386	11,008,345	2,500,817	
							Tot. Company Depr. Exp. 26,467,953							**MN Jurisdiction Depr. Exp. 22,324,156**
50	Property Tax 5/	654,160	663,923	3,534,410	4,569,348	-	PROPTAX	0 865899	566,436	574,890	3,060,441	3,956,592	-	
51	Payroll Taxes 5/	135,446	131,223	503,786	522,783	11,739	LABOR	0 870129	117,856	114,181	438,359	454,889	10,214	
G	**Total Revenue Requirements**													
52	Annual Revenue Requirements	18,486,943	18,027,167	107,646,681	140,695,114	10,740,401			15,634,680	15,246,908	91,025,090	119,025,098	9,065,112	

Notes: 1/ Minnesota Composite Income Tax Rate
2/ Because Boswell 4 and Common have Contra AFUDC, cannot use only DPROD to allocate Avg. Test Year Net Plant, refer to Sections A, B, C allocated above.
3/ Individual components of cash working capital allocated as shown in the Cash Working Capital-Detail tab.
4/ Minnesota Power's proposed pre-tax rate of return of 11.49%
5/ Per MP's 2017 Test Year Budget.
6/ Total Boswell amount allocated among units and common based on net plant in service (Line 26)

OAG No. 106

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota	**MPUC Docket No.**	E015/GR-16-664
By: Ryan Barlow	**Date of Request:**	March 29, 2017
Telephone: (651) 757-1473	**Due Date:**	April 10, 2017

For all responses show amounts for Total Company and the Minnesota retail jurisdiction unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Provide this information in Excel format with formulas intact.

Reference: Direct Schedule G-2 Charitable Contributions

Update the schedule on page 1 with actual charitable contributions for the years 2012 and 2016.

RESPONSE:

Attached is OAG IR 106.01 Attach with actual charitable contributions for the years 2012 and 2016.

Witness:	Marcia A. Podratz
Response by:	Sara Carlson
Title:	Cost & Pricing Analyst Senior
Department:	Rates
Telephone:	218-355-3019

Direct Schedule G-2
Minnesota Power
Charitable Contributions

Donations:	FERC #426.1	Normalized	
2012 Actual	776,855	776,855	
2013 Actual	33,054	533,254	[1]
2014 Actual	1,558,673	1,058,473	
2015 Actual	1,127,042	1,127,042	
2016 Actual	292,080	292,080	[2]

[1] $500,200 Donation recorded in January 2014 but was related to 2013.
[2] Based on draft of 2016 FERC Form 1.

OAG No. 152

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota	**MPUC Docket No.**	**E-015/GR-16-664**

By:	Ian Dobson	**Date of Request:**	May 17, 2017
Telephone:	(651) 757-1432	**Due Date:**	May 30, 2017

For all responses show amounts for Total Company and the Minnesota retail jurisdiction unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Direct Schedule G-3, page 2.

Provide documentation from each organization listed below identifying funds spent on lobbying, legislative advocacy, regulatory advocacy, marketing, public relations, advertising, donations, club dues, and any other functions identified by each organization.

RESPONSE:
Minnesota Power objects to this request as vague as the request states it seeks information on "each organization listed below" but does not provide the list. Further, assuming the referenced organizations are intended to be those set forth in Direct Schedule G-3, p. 2, the request is overly broad and unduly burdensome as it essentially seeks information regarding any function identified by organizations in an extensive list of Corporate Membership Dues for many organizations, many of which have already been addressed in prior OAG Information Requests (see OAG IR 107, OAG IR 140, and OAG IR 141).

Subject to and without waiving this objection, Minnesota Power provides the following information on the organizations listed on Direct Schedule G-3, page 2:

Edison Electric 2015 Membership Dues	OAG 107 and OAG 140
Western Coal Traffic	OAG 107
The Climate Registry	https://www.theclimateregistry.org/who-we-are/about-us/
Bloomberg	https://www.bloomberg.com/ & OAG 141

Witness:	Marcia A. Podratz
Response by:	Sara Carlson
Title:	Cost and Pricing Analyst Senior
Department:	Rates
Telephone:	218-355-3019

Montana Coal Council	OAG 107
Midwest Rural Energy Council	http://mrec.org/
Minnesota Pesticide Information and Education	OAG IR 141
Minnesota Logger Education Program	OAG IR 141
CEATI International	OAG IR 141
Center for Energy Workforce Development	http://cewd.org/
Minnesota Environmental Initiative	OAG IR 140
UWAG	OAG IR 140
Minnesota Mining	OAG IR 140
Minnesota Forest Industries	OAG IR 140
Minnesota High Tech Association	OAG IR 140
Minnesota Timber Producer Association	http://www.mntimberproducers.com/
North American Energy Markets Association	https://www.naema.com/
Cornet Global Midwest	DOC IR 1191
National Association of Manufacturers	http://www.nam.org/
American Wood Protection Association	http://www.awpa.com/
National Coal Transportation Association	http://nationalcoaltransportation.org/
Association for Talent Development Corporation	https://www.td.org/
Shareholder Services Association	DOC IR 1191
Convey Compliance Systems LLC	DOC IR 1191
Corporate Executive Board	DOC IR 1191, OAG 107, & OAG IR 141, item 3)
Energy Solutions – MISO RTO/ISO Markets	OAG IR 141
Mediapro Computer Security	https://www.mediapro.com/
Navex Global Inc Ethics and Compliance	http://www.navexglobal.com/en-us/roles/ethics-compliance
Open Access Technology International Inc	https://www.inc.com/profile/open-access-technology-international
SEPA Smart Electric Power Association	https://sepapower.org/
SNL Financial – Regulatory Research	http://www.snl.com/
World Steel Dynamics Incorporated	http://worldsteeldynamics.com/
Windcast Poweriq Service	http://www.genscape.com/solutions/power/...market-forecasting/windcast-iq
Better Business Bureau of Minnesota	https://www.bbb.org/
CEB Audit Leadership Council	See Corporate Executive Board, above
Financial Accounting Standards Board	http://www.fasb.org/home
National Hydropower Association	OAG IR 140
Public Company Accounting Oversight Board	https://pcaobus.org//

Witness: Marcia A. Podratz
Response by: Sara Carlson / David R. Moeller
Title: Cost and Pricing Analyst Senior / Senior Attorney
Department: Rates / Legal Department
Telephone: 218-355-3019 / 218-355-3963

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

OAG No. 117

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota	**MPUC Docket No.**	E015/GR-16-664
By: Ryan Barlow	**Date of Request:**	April 25, 2017
Telephone: (651) 757-1473	**Due Date:**	May 5, 2017

For all responses show amounts for Total Company and the Minnesota retail jurisdiction unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Provide this information in Excel format with formulas intact.

Reference: Schedule G-3 Corporate Membership Dues

1. Provide the EEI membership invoices that Minnesota Power is seeking cost recovery for.
2. Identify all EEI lobbying-related activities funded by the Company's EEI membership. Confirm whether or not membership dues attributable to lobbying-related activities have been removed from the test year.
3. Identify all other EEI political activities (not already captured in the question above) that are funded by the Company's EEI membership. Confirm whether or not membership dues attributable to political activities have been removed from the test year.
4. Identify all EEI advertising and marketing-related activities funded by the Company's EEI membership. Confirm whether or not membership dues attributable to advertising and marketing-related activities have been removed from the test year.
5. Describe all benefits (direct or otherwise) that ratepayers obtain from the Company's EEI membership. Be specific about the cost savings that have been realized for ratepayers as a result of the Company's EEI membership.

Provide this information in Excel with all formulas intact.

RESPONSE:

1. EEI 2017 member due invoices are contained in OAG IR 117.01 Attach TS.

Witness:	Marcia A. Podratz
Response by:	Sara Carlson
Title:	Cost & Pricing Analyst Senior
Department:	Rates
Telephone:	218-348-4600

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

2. EEI lobbying activities include working on bills related to the following issues and topics: energy, taxes, general utility issues, homeland security matters (cyber & physical threats), environmental, communications and labor. Recent environmental issues have included greenhouse gases, mercury and air toxic standards, regional haze, and fall out issues related to energy transformation.

As shown in OAG IR 117.02, 2017 EEI actual membership dues expense which excluded lobbying exceeded the 2017 budgeted EEI membership dues. The 2017 budget estimated EEI dues was based on the 2015 actuals.

3. It is Minnesota Power's understanding that all of EEI's political activities are accounted for in the lobby-related activities. Specifically, the lobbying portion of EEI's dues is calculated and reported each year using the Internal Revenue Code's (IRC) definition of "lobbying and political activities" as required to be reported on IRS Form 990. In filings required under the Lobbying Disclosure Act, EEI elects to use the same IRC definition, which broadly captures not only federal lobbying, but also state and grassroots lobbying and political activities.

4. EEI provides information to its member organizations in various ways but is not in the business of providing marketing or advertising services. As a national trade association, EEI's communications department is a resource for keeping tabs on national or international trends and helping members understand or frame issues, but they do not provide any direct advertising or marketing services.

5. Minnesota Power customers benefit from EEI's technical expertise and advisory leadership related to complex electric utility issues of common interest to its membership. To replicate their services on an individual company basis would be far too expensive for any utility.

EEI's committee system supports technical data gathering, sharing, and analysis related to generation, transmission, and distribution of energy. EEI has various advisory committee and task forces that track issues across the country, and help companies identify solutions and best practices. EEI provides common sense solutions that limit costs that are ultimately passed to customers. EEI also provides value by having a readily available set of peers from which to ask questions of or seek input.

The information contained in OAG IR 117.01 Attach TS constitutes information Minnesota Power considers to be trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). This information, which includes proprietary banking and account information, has important economic value to Minnesota Power as a result of this information remaining not public, and Minnesota Power has taken reasonable precautions to maintain its confidentiality.

Witness:	Marcia A. Podratz
Response by:	Sara Carlson
Title:	Cost & Pricing Analyst Senior
Department:	Rates
Telephone:	218-348-4600

RECEIVED
By Jillian Wahto at 1:28 pm, Dec 30, 2016

Invoice for Membership Dues

Edison Electric INSTITUTE

MR. ALAN R. HODNIK
CHAIRMAN, PRESIDENT & CEO
ALLETE
30 W SUPERIOR ST
DULUTH, MN 55802-2093

Date	Invoice Number
12/07/2016	DUES201702

Payment due on or before 1/31/2017

Description	Total
2017 EEI Membership Dues for:	
Regular Activities of Edison Electric Institute [1]	$291,679
Industry Issues [2]	29,168
Restoration, Operations, and Crisis Management Program [3]	2,000
2017 Contribution to The Edison Foundation, which funds IEI [4]	~~15,000~~
Total	~~$337,847~~ 322,847

1 The portion of 2017 membership dues relating to influencing legislation, which is not deductible for federal income tax purposes, is estimated to be 13%.

2 The portion of the 2017 industry issues support relating to influencing legislation is estimated to be 25%.

3 The Restoration, Operations, and Crisis Management Program is related to improvements to industry–wide responses to major outages (e.g. National Response Event); continuity of industry and business operations; and EEI's all hazards (storms, cyber, etc.) support and coordination of the industry during times of crises. No portion of this assessment is allocable to influencing legislation.

4 The Edison Foundation is an IRC 501(c)(3) educational and charitable organization. Contributions are deductible for federal income tax purposes to the extent provided by law. Please consult your tax advisor with respect to your specific situation.

PLEASE NOTE INFORMATION FOR ELECTRONIC PAYMENT

The following instructions should be used when transferring funds electronically (ACH or wire) to Edison Electric Institute:

Beneficiary's Bank: [redacted]
Bank's Address:
Bank's ABA Number:
Beneficiary:
Beneficiary's Acct No:
Beneficiary's Address:

Beneficiary Reference: 2017 Membership Dues

Please refer any questions to Terri Oliva, EEI Controller: (202) 508-5541 *or* memberdues@eei.org

2017 Dues

Total Billing

For year ending 12/31/15:	MP Reg	MP Non-Reg	SWLP	ACE (Non-Reg)	Total
Customers	145,053	1	14,704	8	159,766
For year ending 12/31/15: Revenue	908,503,000	14,054,000	60,226,000	64,322,000	1,047,105,000
above $2,000,000,000	-	-	-	-	-
At 12/31/2015: MP (all generation) *(URGE Rating - kWh)*	1,942	29	-	537	2,508
As Calculated					

Based on 2012 Allocation Factors

	Rate	MP Reg	MP Non-Reg	SWLP	ACE	Total
Customers	0.2400000000	$ 34,813	$ 0	$ 3,529	$ 2	$ 38,344
Revenue	0.0001250000	113,563	1,757	7,528	8,040	130,888
above $2,000,000,000	0.0001548000	-	-	-	-	-
MP (all generation)	32.0000000000	62,144	928	-	17,184	80,256
As Calculated		$ 210,520	$ 2,685	$ 11,057	$ 25,226	$ 249,488
		$ 272,421	$ 3,474	$ 14,309	$ 32,643	$ 322,847

	URGE	Rev (after elim)
TH	-	$ -
Rapids	25.500	$ 15,700,240
Cloquet	-	$ -
	25.500	$ 15,700,240

Total	W.O.- CT.	Total
[redacted]		
MP Non-Reg (Rapids Energy Ctr) (Non-Lobbying)	1733976-3110	$ 2,987
MP Non-Reg (Rapids Energy Ctr) (Lobbying)	1733977-3110	$ 487
[redacted]		
MP (Non-Lobbying)	1733965-3110	$ 234,272
MP (Lobbying)	1733970-3110	$ 38,149
SWL&P (Non-Lobbying)	1733973-3110	$ 12,305
SWL&P (Lobbying)	1733975-3110	$ 2,004
Allete Clean Energy (Non-Lobbying)	DUEACENLBY - 3110	$ 28,072
Allete Clean Energy (Lobbying)	DUEACELBY - 3110	$ 4,571

Total

MP Regulated

Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696
USA
A/R Phone Number : (202) 508 5428
A/R E-Mail : accountsreceivable@eei.org

Minnesota Power
30 W Superior Street
Duluth, MN 55802-2093

Invoice

Invoice # : 194227
Invoice Date: 01/24/2017
FEIN: 13-0659550

Description	Quantity	Price	Discount	Amount
2017 USWAG Membership Dues	1	$22,500.00	$0.00	$22,500.00

This invoice is for the 2017 Utility Solid Waste Activities Group (USWAG) Membership Dues. The portion of 2017 membership dues relating to influencing legislation, which is not deductible for federal income tax purposes is estimated to be 3%. If you have questions concerning the USWAG program, please contact Gayle Novak, at 202-508-5654. If you have questions regarding payment for this invoice, please contact Carol Ray, in EEI's Internal Accounting Department, at 202-508-5428.

Invoice Total	$22,500.00
Taxes	$0.00
Amount Paid	$0.00
PLEASE PAY	**$22,500.00**

PLEASE DETACH AND REMIT WITH YOUR PAYMENT

Invoice #: 194227

Minnesota Power
30 W Superior Street
Duluth, MN 55802-2093

Payment Method

Check: Made payable to Edison Electric Institute

[redacted]

Reference: Invoice number & purpose of payment

Please note you are responsible for any ACH or wiring fees.

Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696
USA
A/R Phone Number : (202) 508 5428
A/R E-Mail : accountsreceivable@eei.org

Minnesota Power/ALLETE
30 W Superior Street
Duluth, MN 55802-2093

Invoice

Invoice # : 193075
Invoice Date: 12/16/2016
FEIN: 13-0659550

Description	Quantity	Price	Discount	Amount
2017 UARG Membership Dues	1	$102,000.00	$0.00	$102,000.00

This invoice is for your participation in the Utility Air Regulatory Group (UARG) for the calendar year 2017. If you have questions about the program, please contact Andrea Field at 202-955-1558. If you have questions regarding this invoice or to make payment arrangements, please contact Carol Ray, in EEI's Internal Accounting Department, at 202-508-5428.

Invoice Total	$102,000.00
Taxes	$0.00
Amount Paid	$0.00
PLEASE PAY	**$102,000.00**

PLEASE DETACH AND REMIT WITH YOUR PAYMENT

Invoice #: 193075

Minnesota Power/ALLETE
30 W Superior Street
Duluth, MN 55802-2093

Payment Method
Check: Made payable to Edison Electric Institute
[redacted]
Reference: Invoice number & purpose of payment
Please note you are responsible for any ACH or wiring fees.

2017 Test Year Edison Electric Institute	
EEI Base Member Dues - MP Regulated	284,333
EEI - USWAG Member Dues [1]	27,000
EEI - Avian Power Interaction [2]	5,000
Rounding	667
Total 2017 Test Year	317,000

2017 EEI Invoices received to date:	
MP Regulated Base Member Dues [3]	234,272
EEI - USWAG Member Dues	22,500
EEI - UARG [4]	102,000
Total 2017 Actual	358,772

[1] Utility Solid Waste Activity Group
[2] Avian Power Interaction Committee
[3] Non Lobbying related portion only. Lobbying related dues of $38,149 has been expensed to FERC account 426.4, Certain civic, political & related activities.
[4] Utility Air Regulatory Group